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Exhibit No.: SCE-04A
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(U 338-E)

***Phase 2 of 2025 General Rate Case
Amended Rate Design Proposals***

Before the

Public Utilities Commission of the State of California

Rosemead, California
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SCE-04A: Amended Rate Design Proposals

GRC Phase 2

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1 I.

2 **OVERVIEW**

3 This exhibit describes SCE's rate design and pricing proposals for each of its consumer groups.
4 Section II addresses SCE's proposed pricing criteria. Sections III through VII provide rate design
5 proposals specific to each of the following five consumer groups: residential; general service (*i.e.*, small
6 and medium commercial and industrial (C&I) power and lighting, small standby); large power
7 (including large standby customers); agricultural and pumping (A&P); and street and area lighting.
8 Section VIII describes SCE's newest Economic Development Rate (EDR) Proposal and Section IX
9 describes SCE's Vehicle-to-Grid Resource Proposal (VGRP). Summaries of these proposals are
10 included in Exhibit SCE-01.

1 II.

2 **PRICING CRITERIA**

3 **A. The Revenue Requirement Applied To SCE's Rate Design Proposals**

4 Unless specifically noted, the illustrative rates proposed in Appendix B for SCE's delivery and
5 generation services do not account for changes to SCE's revenue requirements that may be authorized
6 between the date of this Application and the effective date of rates adopted in this proceeding. Here, the
7 revenue requirements are the authorized functional revenues that SCE used to establish rates on October
8 1, 2023, applied to the 2025 test year sales forecast for bundled and unbundled service customers from
9 SCE's Phase 1 GRC filing – functional revenues and rates for Generation Service are assessed on
10 Bundled Service customers and functional revenues and rates for Delivery Service are assessed on both
11 Bundled and non-Bundled customers, Application (A.)23-05-010. A comparison of October 1, 2023
12 rates ("current rates") and proposed rates is presented in Appendix B. As noted in Exhibit SCE-03,
13 SCE's illustrative rates are calculated at their full marginal cost-based levels.

14 Because the Federal Energy Regulatory Commission (FERC) establishes SCE's transmission
15 revenue requirement and associated rates, the retail transmission rates reflected in this testimony are
16 provided solely to illustrate total rates.

17 Similarly, non-bypassable charges (NBCs) reflect their respective revenue requirements as of
18 October 1, 2023 and the currently-approved allocation methodologies, pursuant to statute, Commission
19 guidance, or the 2021 general rate case (GRC) settlement agreement.¹

20 With respect to Direct Access (DA), Community Aggregation (CA), and Community Choice
21 Aggregation (CCA) customers' departing load obligations, the Cost Responsibility Surcharge (CRS)
22 continues to include SCE's Competition Transition Charge (CTC), the Wildfire Fund Non-Bypassable

¹ Decision (D.)22-08-001, Decision Adopting Settlements on Marginal Cost, Revenue Allocation, And Rate Design (hereinafter "2021 GRC Phase 2 Settlement Agreement"), was adopted by the California Public Utilities Commission (Commission or CPUC) on August 4, 2022 to resolve all issues in A.20-10-012, SCE's 2021 GRC Phase 2 proceeding.

Charge (WFC), and the Power Charge Indifference Adjustment (PCIA). Pursuant to D.19-10-001, SCE applies vintage-based billing determinants when determining rate group-specific CRS charges.²

B. Basic Rate Structures And Common Rate Components

This section discusses basic rate structures and common rate components that are included in SCE's non-residential, non-lighting rate schedules, and residential rate schedules, in addition to specific demand response (DR) options available to all customer classes. The proposed rates are based on the underlying marginal cost components discussed in Exhibit SCE-02 and the revenue allocations discussed in Exhibit SCE-03.

Overview Of Non-Residential, Non-Lighting Rate Schedules

The non-residential and non-lighting rate schedules are applicable to commercial and industrial (C&I) (*i.e.*, general service) and agricultural and pumping (A&P) customers. SCE offers two basic rate structures for these classes of customers, *Option-D*³ and *Option-E*, which were first introduced in Phase 2 of SCE's 2018 GRC.⁴ Both structures use the time-of-use (TOU) periods adopted in SCE's 2016 Rate Design Window (RDW) proceeding,⁵ and include a combination of customer (dollar-per-month), TOU energy (cents-per-kilowatt-hour) and demand (dollar-per-kilowatt) charges. The two basic structures differ only in the rate mechanism used to recover distribution peak and generation peak capacity costs. Option D recovers these costs primarily through time-related demand (TRD) charges, while Option E recovers these peak capacity costs through TOU energy charges.

Under SCE's proposed rate structures, both Option-D and Option-E have some distribution costs recovered via TOU charges (energy or demand) and the proposed Option-E continues to recover

² See D.19-10-001, OP 6.

³ With the exception of TOU-GS-1 customers, Option D is designed to be the base or standard rate structure for the C&I and A&P rate schedules.

⁴ D.18-11-027, at p. 63 ("This decision adopts rate designs and resolves related issues for SCE considered in A.17-06-030. This decision approves all of the settlements filed in this proceeding and creates two main forms of rate design for SCE's non-residential customers: Option D rates and Option E rates.").

⁵ D.18-07-006.

1 generation capacity costs via a TOU energy price signal.⁶ SCE maintains current eligibility and
2 participation cap requirements for large power customers subscribing to SCE's Option-E rate schedule.⁷

3 **Overview Of Residential Rate Schedules**

4 In this application SCE has updated its default Time-of-Use (TOU) rates for residential
5 customers, with marginal costs presented in Exhibit SCE-02 and revenue allocations presented in SCE-
6 03 as a starting point. The default residential TOU rates include considerations that reflect Commission
7 policy on affordability and bill stability. SCE complements residential default rates with a broader suite
8 of optional TOU rates to facilitate greater levels of load and demand response.⁸ SCE also continues to
9 offer inclining block legacy tiered rates to eligible customers. The default TOU residential rates are
10 designed to recover almost all costs via volumetric TOU energy charges (cents-per-kWh) and include a
11 baseline credit. The baseline credit in residential TOU rates is a holdover element from the legacy tiered
12 rates and effectively lowers the amount residential customers pay for their baseline usage. A monthly
13 fixed charge is used to recover a nominal portion of distribution costs, with a balance of minimum
14 charge applied when cost recovery falls below a level to sufficiently cover the cost of service. The
15 balance of minimum charge is assessed inclusive of the Conservation Incentive Adjustment (CIA)
16 component.

17 In Track A of R.22-07-005, the Commission is expected to issue a final decision addressing the
18 level of fixed charge applicable for residential rates. Residential rate proposals in this Application are
19 subject to changes that may be adopted in that final CPUC decision; SCE proposes to file supplemental
20 testimony in this proceeding to describe how the changes will flow through rate design. A decision is
21 expected before July 1, 2024.

⁶ For Medium and Large Power customer groups (*i.e.*, Commercial & Industrial (C&I)), SCE retains a time variant demand charge set at 25 percent of the Standby class's Backup Demand Charge.

⁷ Eligibility for Option E is limited to customers with qualifying technologies whose annual peak demands do not exceed 5 MW and there is a 250 MW participation cap specific to customers who adopt Distributed Energy Resource technologies.

⁸ D.19-07-004 adopted SCE's Residential Default TOU Rate Structures.

1 SCE notes that most customers taking service on tiered rates are those customers who reside in
2 hotter climate zones and/or in environmentally or economically disadvantaged communities.⁹ As such,
3 SCE will continue to recover revenue imbalances resulting from participation in optional tiered rates
4 from all customer classes as is the standard for non-residential forecast driven revenue imbalances.¹⁰

5 **Common Price Elements**

6 In this section, SCE provides a summary of common pricing elements included in retail rates
7 proposed in this Application. In recognition of the need to maintain rate stability across GRC cycles,
8 SCE proposes to retain some of the pricing elements established in the 2021 GRC Phase 2 settlement
9 agreements that pertain to generation and distribution rate design for various rate groups. Sections III-
10 VII provide more detail on the specific rate design proposals for each rate group.

11 **1. Customer Charges**

12 Consistent with previous GRC Phase 2 proceedings, SCE continues to set a monthly
13 customer charge (dollar-per-month) to recover all or a portion of the customer-related distribution
14 marginal costs. For most non-residential rate groups, the customer charge is scaled on an Equal Percent
15 Marginal Cost (EPMC) basis to recover authorized revenue requirements.¹¹ Customer charges are
16 associated with costs for connecting a customer to SCE's delivery system, and typically include the cost
17 of a final line transformer, service drop and meter. In addition to costs for on-going customer service
18 and billing.

19 For non-residential customers with demands exceeding 20 kW, SCE applies a rate setting
20 adjustment where the costs associated with 50 kVA of final line transformation are recovered through
21 the grid related portion of the distribution charge. This adjustment promotes bill stability when small
22 commercial customers transition to higher demand level rate groups due to increases in their monthly
23 demand resulting from a marginal change in operations. Pursuant to SCE's tariffs, a TOU-GS-1

⁹ D.19-07-004 specifically excluded customers enrolled and *eligible* for CARE and FERA programs in hotter climate zones 10, 13, 14, 15.

¹⁰ Please see Section I.C.8 of Exhibit SCE-03 for a specific discussion concerning the treatment for imbalances related to residential customers on tiered rates.

¹¹ An EPMC scalar is used to adjust rates set based on marginal cost revenue requirements to the rate levels necessary to recover authorized revenue requirements.

customer with a demand that exceeds 20 kW three times in a 12-month period is transitioned to the TOU-GS-2 rate group. Absent the 50 kVA transformer treatment, the transition to the higher demand rate group can result in a significant bill impact as the customer's load essentially remains the same, however the customer charge would now reflect the higher charge associated with the TOU-GS-2 rate group. Recovery of transformer costs through the distribution grid component, as proposed, helps alleviate the upward pressure on bills.

Table II-1, below, provides a comparison of current monthly customer charges and the proposed EPMC-based monthly customer charges inclusive of the rate design adjustment SCE makes for the final line transformer discussed in the previous paragraph.

Table II-1
EPMC-Based Customer Charges
(\$/Customer/Month)

Rate Group	Current Effective Customer Charge (\$/cust-month)	Proposed Full EPMC Customer Charge (\$/cust- month)	Percent Difference
Domestic	0.94	0.94	0%
TOU-GS-1	14.24	18.87	33%
TC-1	23.97	22.66	-5%
TOU-GS-2	188.98	140.00	-26%
TOU-GS-3	544.34	748.75	38%
TOU-8-Sec	355.45	1,641.00	362%
TOU-8-Pri	367.81	202.50	-45%
TOU-8-Sub	3,458.53	3,828.75	11%
TOU-PA-2	72.69	32.75	-55%
TOU-PA-3	427.99	572.75	34%
Street Lights	11.46	8.25	-28%
STANDBY/SEC	355.45	1,641.00	362%
STANDBY/PRI	367.81	202.50	-45%
STANDBY/SUB	3,458.53	3,828.75	11%

In this application, SCE maintains the current methodology for establishing customer charges and minimum charges for residential customers that is subject to change should the Commission issue a Final Decision in Track A of R.22-05-007 before the implementation of rates authorized in this proceeding.

2. Energy Charges

Energy charges are established on a per-kWh basis to recover the following: (1) all or a portion of SCE's costs of generation energy and capacity; (2) some portion of distribution peak capacity costs; (3) grid-related distribution costs (for certain rate schedules); (4) nuclear decommissioning costs; (5) new system generation charges; (6) transmission-related costs for non-demand metered rate groups and balancing accounts; (7) the Fixed Recovery Charge; (8) the Wildfire Fund Non-Bypassable Charge (WFC)¹²; and (9) Public Purpose Program costs.

Generation marginal costs are determined for both energy and capacity cost components, as described in Exhibit SCE-02. The increased penetration of distributed energy resources coupled with the increase of renewable resources in the generation supply portfolio have had the effect of imposing capacity constraints in both summer and winter seasons: *peak* constraints in the summer; and *ramp* constraints primarily in the winter. As capacity constraints evolve on the system, SCE will continue to evaluate the merits of including the winter ramp constraint when designing SCE's winter peak period generation rates.

Generation energy (kWh) marginal costs are determined from simulations computed in a production cost model and form the basis of retail generation energy rates. The increased mix of renewables has led to higher energy prices later in the day with a low-cost period during the middle of the day in the winter season. For the Option-D and Option-E rate structures, generation energy charges include the EPMC scaled, average unit Generation Energy marginal cost for each TOU period, adjusted for service level losses across individual consumer groups.

Generation capacity (kW) marginal costs that reflect both peak and ramp system constraints are typically designed as time-variant demand charges (i.e., TRD) and applied in relative proportion to both summer on-peak and winter mid-peak periods, with a portion of non-peak capacity related costs recovered in energy charges.

¹² SCE implemented the WFC in January 2022. The WFC is recovered from customers in the same manner as was the Department of Water Resources (DWR) Bond Charge.

1 For rate schedules that do not require demand meters, including all domestic and lighting
2 rate schedules, Generation Energy and Generation Capacity marginal costs are recovered through a cent-
3 per-kWh charge.

4 For all demand metered rate schedules' Option-E rate structure, generation energy
5 charges reflect both Generation Energy and Generation Capacity marginal costs with the latter recovered
6 through a cent-per-kWh charge across the respective seasonal TOU periods.¹³

7 **Distribution capacity (kW) marginal costs** are recovered through a combination of flat
8 and TOU cent-per-kWh energy charges, TOU dollar-per-kW demand charges, and non-time variant
9 dollar-per-kW demand charges.

10 For rate schedules that do not require demand meters, including all domestic and lighting
11 rate schedules (including Schedules WTR and TC-1), all Distribution Peak Capacity and Distribution
12 Grid Capacity marginal costs are recovered via cent-per kWh energy charges.

13 For Medium and Large Power¹⁴ (i.e., Commercial & Industrial (C&I)) customers' Option
14 D rate structure, distribution energy charges reflect 95 percent of the summer non-peak Distribution
15 Peak Capacity marginal costs as an equal cent-per-kWh charge across the summer TOU periods, which
16 is then TOU shaped by applying a 10 percent increase for the peak period and a commensurate percent
17 decrease in the off-peak period.¹⁵ Similarly in the winter, the mid peak rate is increased by 10 percent
18 and winter super-off peak is decreased by 10 percent For the Option-E rate structure, SCE recovers
19 distribution design demand revenues, with 60 percent via TOU cent-per-kWh Energy Charges, 30

¹³ For Medium and Large Power customer groups, energy and capacity revenues are recovered through TOU cent-per-kWh energy charges coupled with a time variant demand charge set at 25 percent of the respective Standby class's Backup Demand Charge.

¹⁴ Medium and Large Power includes the following rate groups: TOU-GS-2, TOU-GS-3, and TOU-8 (including Standby).

¹⁵ The remaining 5 percent of the off-peak capacity costs along with the summer on- and mid-peak period costs are recovered through time variant dollar-per-kW demand charge in the summer. All winter distribution peak capacity marginal costs are recovered as a time variant demand charge in the winter mid-peak period. For TOU-8-SUB rate group, no distribution costs are recovered via energy charges.

1 percent via a non-time variant dollar-per-kW demand charge, and 10 percent via equal cent-per-kWh
2 energy charges.¹⁶

3 For Agricultural & Pumping customers' Option-D rate structure, distribution energy
4 charges reflect approximately 50 percent of the on-peak Distribution Peak Capacity marginal costs, all
5 mid-peak, and all off-peak costs.¹⁷ Option-E rate structure does not include a distribution TRD charge,
6 thus all distribution peak capacity marginal costs are recovered through TOU cent-per-kWh energy
7 charges.

8 **Other Charges** such as Wildfire Fund Charge (WFC), FERC transmission (for non-
9 demand metered customers and balancing accounts), Nuclear Decommissioning Charge (NDC), New
10 System Generation Charge (NSGC), the Fixed Recovery Charge (FRC), and Public Purpose Programs
11 Charge (PPPC) revenue requirements and are added to the generation and distribution energy charges
12 described above to produce total seasonal time-variant energy charges.¹⁸

13 **3. Time-Related Demand (TRD) Charges on Demand-Metered TOU Schedules**

14 Generation Capacity and Distribution Peak Capacity marginal costs are typically
15 designed as time variant demand charges (i.e., TRD) for default Option-D rate schedules and applied in
16 relative proportion to both summer on-peak and winter mid-peak periods.¹⁹

¹⁶ Consistent with the Medium and Large Power Rate Group Settlement Agreement adopted in D.22-08-001 (*Attachment A19-22*), SCE retains the percent of distribution revenue recovery between energy and demand charges for all medium and large power Option E designs except for the TOU-8-SUB rate group. The settlement agreement adopted a separate design for TOU-8-SUB rate group, in which the energy charges are designed to recover all peak capacity cost. In addition, SCE continues to retain the energy rate adder for TOU-GS-3 to limit the extent of potential revenue imbalance caused by converting the recovery of a portion of distribution grid costs from non-coincident demand charges to cents-per-kilowatt-hour energy charges.

¹⁷ For Agricultural and Pumping customers, the remaining 50 percent of the on-peak distribution peak capacity marginal costs are recovered through a time related demand (TRD) charge. The facilities related demand charge is designed to recover: (1) approximately 50 percent of peak-capacity distribution marginal costs of the mid-, off-, and super-off-peak periods, (2) all grid capacity marginal costs, and (3) the portion of customer marginal costs not recovered via the customer charge.

¹⁸ Residential tiered rate schedules do not include time-variant energy charges.

¹⁹ As designed, capacity marginal costs could be recovered in all 6 TOU periods. However, considering customer understandability and adoption of the 4 p.m. to 9 p.m. peak periods, SCE retains the two period TRD adopted in the 2018 GRC. SCE also applies TRD charges to non-holiday weekdays only, and not to weekends or holidays.

1 a) Generation TRD Charges

2 The proposed generation TRD charges are designed using the cost disposition of
3 system peak and flexible capacity marginal costs as described in SCE-02. Generation capacity costs are
4 allocated to the summer season where system peak capacity constraints are typically expected and
5 winter season where system ramp capacity constraints are typically expected.²⁰ SCE continues to
6 evaluate the merits of including ramp capacity constraints in the design of winter peak-period retail
7 rates.

8 For non-demand metered rate schedules, all generation-related marginal costs are
9 recovered through cent-per-kWh energy charges. For the demand metered rate schedules, the Option-D
10 rate structure recovers generation capacity costs via summer on-peak and winter mid-peak (4 p.m. to 9
11 p.m. weekdays) TRD charges.²¹ For the demand metered rate schedules, the Option E rate structure
12 typically recovers generation capacity costs through TOU cent-per-kWh energy charges.²²

13 b) Distribution TRD Charges

14 Proposed distribution TRD charges are designed using the cost disposition of
15 Distribution Peak Capacity marginal costs as described in SCE-02. In this GRC, SCE continues to
16 functionalize design demand marginal costs into Peak Capacity marginal cost and Grid Capacity
17 marginal cost. With this functional split, a portion of Distribution Peak Capacity marginal costs are
18 recovered as TRD charges.²³

19 For non-demand metered rate schedules, including all domestic and lighting rate
20 schedules, TRD charges do not apply. For demand metered rate schedules distribution peak capacity

²⁰ Approximately 39 percent of marginal generation capacity cost revenue responsibility is now allocated to the winter season.

²¹ Summer mid-peak and off-peak generation capacity costs are recovered via energy charges. TRD charges are designed and apply to non-holiday weekdays only; not on weekends or holidays.

²² For *Medium and Large Power customer groups* (i.e., Commercial & Industrial (C&I), SCE retains a time variant demand charge set at 25 percent of the Standby class' Backup Demand Charge.

²³ In this application, SCE continues to apply TRD charges to only the summer on-peak and winter mid-peak periods. This approach allows customers to adapt to prices under the new TOU periods. Additionally, SCE retained application of TRD charges to non-holiday weekdays only, and not to weekends or holidays.

1 marginal costs are recovered via a combination of TRD charges and time-varying cents-per kWh energy
2 charges.

3 For Medium and Large Power (i.e., Commercial & Industrial (C&I)) customer's
4 Option-D rate structure, all winter Distribution Peak Capacity costs are recovered as a time variant
5 demand charge (i.e., TRD charge) in the winter mid-peak period. Summer on-peak TRD charges
6 recover the summer on-peak costs, mid-peak costs, and 5 percent of the off-peak capacity costs.²⁴

7 For Agricultural and Pumping customer's Option-D rate structure, 50 percent of
8 the on-peak Distribution Peak Capacity marginal costs are recovered through a TRD charge.²⁵

9 **4. Non-Time Coincident Demand Charges (Facilities Related Demand Charges)**

10 As discussed in Exhibit SCE-02, the Distribution Grid Capacity marginal costs reflect the
11 functionality of the distribution system as a grid capacity resource – one that enables both geographical
12 connectivity, bi-directional flow of power to and from customers or, between load centers, and for the
13 higher voltage distribution system, the network/mesh configuration that enhances the reliability and the
14 resiliency of the distribution system. Non time variant demand charges, otherwise referred to as
15 Facilities Related Demand (FRD) charges, are designed to recover marginal costs that are functionalized
16 as Distribution Grid Capacity costs.²⁶ Based on marginal cost principles discussed in SCE-02, the use of
17 FRD charges is appropriate for both the Option D and Option E rate structures as customers use grid
18 infrastructure for both electricity deliveries and to export energy to the grid (when needed), as well as
19 depending on the resiliency and reliability of the high-voltage distribution system to meet all their
20 consumption needs. Specifically, Distribution Grid Capacity marginal cost revenues are recovered via
21 dollar-per-kW, non-time variant demand charges applied to customers' monthly maximum demand. For

²⁴ The TOU-8-SUB rate group has a unique rate design where distribution TRD charges are designed to recover summer on- and winter mid-peak capacity costs, with the balance of the capacity cost to be recovered via the non-time dependent facilities related demand charge.

²⁵ Approximately 50 percent of Peak-related distribution design demand marginal costs of the mid-, off-, and super-off-peak period are recovered through a non-time variant peak demand charge (*i.e.* Facilities Related Demand charge).

²⁶ Because the recovery of grid costs is equally applicable regardless of the direction of the flow of power on the grid, distribution grid-related demand charges will continue to be assessed on metered demand associated with energy delivered to a customer site. SCE does not intend to assess the grid-related demand charge on metered demand associated with energy supplied to the grid from a customer site.

1 non-demand metered rate schedules, including all domestic and lighting rate schedules, distribution grid
2 cost revenues are recovered via equal-cents-per kWh energy charges across all TOU periods.

3 **5. Demand Response (DR) And Dynamic Pricing Programs**

4 As directed by the Commission, SCE incorporated DR program incentives in its 2018-
5 2022 DR application, A.17-01-012, but excluded dynamic pricing programs such as Critical Peak
6 Pricing from that application.²⁷ On December 21, 2017, the Commission issued D.17-12-003 adopting
7 SCE's demand response budgets and incentives, including the Base Interruptible Program (BIP),
8 Agricultural and Pumping Interruptible (AP-I) Program, and the Summer Discount Plan (SDP) Program
9 for program years 2018 through 2022. Consistent with the Commission's direction, SCE includes DR
10 program incentives in relevant DR proceedings, and demonstrates coordination with rate design²⁸ in this
11 Application by including DR program incentives for BIP, AP-I, and SDP. In this Application, SCE
12 presents illustrative incentive rate factors for BIP, AP-I, and SDP that remain consistent with budgets
13 adopted in D.17-12-003.²⁹ Because SCE's Demand Response Incentive rates as presented in the
14 Demand Response Funding Application are designed based on the cost of avoided generation capacity
15 presented in the GRC Phase 2, the costs adopted here will modify demand response incentive rates that
16 will be implemented in concert with rate changes approved and adopted in this proceeding.

17 a) Critical Peak Pricing (CPP) Program

18 CPP is a dynamic pricing rate that is available to residential, C&I and A&P
19 bundled customers. Currently, the program can be called year-round on a day-ahead basis, for five-hour
20 static periods from 4 p.m. to 9 p.m., on any day of the week including holiday weekdays and weekends,
21 for up to 15 events per year.³⁰ CPP customers are charged a significantly higher energy charge during

²⁷ D.16-06-029, OP 22, directed utilities to include DR program incentives in their respective DR applications. D.12-04-045, at p. 138, directed dynamic pricing programs be removed from future DR applications and included in utilities general rate case applications.

²⁸ D.16-09-056, p. 46.

²⁹ Although D.23-12-005 was adopted by the Commission on December 14, 2023, SCE is using the incentive levels associated with the prior DR funding cycle as these revenues are embedded in the October 1, 2023 revenue requirements.

³⁰ D.21-03-056 approved changes to SCE's CPP program to include weekends and holidays.

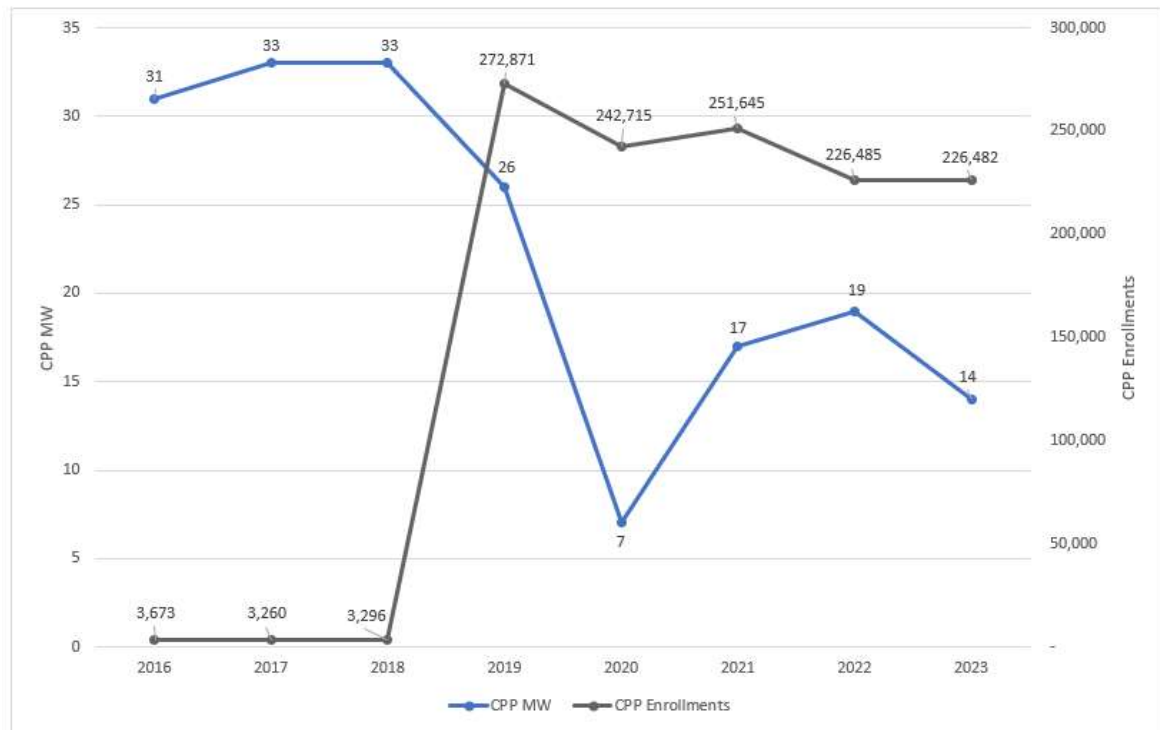
1 CPP event periods, in exchange for lower rates for non-event period usage and/or demand in the summer
2 months.

3 The peak period pricing for CPP rates is an energy charge on a \$/kWh basis at the
4 applicable service voltage level. Revenue neutral offsetting credits are applied to non-event summer
5 energy and/or demand charges, depending on the underlying rate structure. Customers taking service on
6 an eligible underlying rate schedule where capacity costs are included in their demand charges (*e.g.*,
7 TOU-GS-2, TOU-PA-2, TOU-PA-3, TOU-GS-3, TOU-8) will receive reductions in summer on-peak
8 demand charges (\$/kW-month). Customers taking service on an eligible underlying rate schedule where
9 capacity costs are included in the energy charges (*e.g.*, Residential, TOU-GS-1-E) will receive energy
10 credits on a \$/kWh basis that will apply to the summer on-peak non-event kWh usage.

11 (1) Summary of Proposal

12 As described in further detail below, SCE proposes to make several changes to the
13 CPP program, especially for the small and medium commercial CPP customer segments. SCE is
14 concerned with the decrease in available MW available from the overall CPP program, which is largely
15 a result of lower ex ante load impacts attributed to CPP customers due to a large influx of non-
16 performing small and medium commercial CPP customers that were defaulted onto the program. As
17 shown in Figure II-1 below, the CPP program in 2023 provided less than half of what it did prior to
18 default enrollment of small and medium commercial customers.

Figure II-1
CPP Program, 2016-2023
Enrollments and August Ex Ante MW



SCE is also concerned that defaulting small commercial customers to CPP is inconsistent with recent Commission policy direction, that the CPP program is inappropriate for small and medium commercial customers given their mandatory TOU rates, and that SCE is spending money for little benefit due to the program's current structure. Based on its experience with and analysis of the CPP program, SCE proposes the following improvements, as explained more fully below:

- Make CPP an opt-in rather than a default program.
- Modify the CPP dispatch hours.
- Remove non-performing customers from the program.

1 (2) Background

2 In D.09-08-028, the Commission adopted SCE's proposal to make CPP rates
3 optional for residential, agricultural, and C&I customers with demands less than 200 kW, and in October
4 2009, SCE made these rate schedules available to eligible customers. In D.09-08-028, the Commission
5 also ordered SCE to implement default CPP rates for C&I customers with demands less than 200 kW no
6 later than January 1, 2012. SCE filed its proposal in A.10-09-002, which was later deferred to its 2012
7 GRC Phase 2 application by the Executive Director of the Commission.

8 In its 2012 GRC Phase 2 application, A.11-06-007, SCE included a compliance
9 proposal faithful to the Commission's order in D.09-08-028 and included an alternate proposal that
10 departed from the compliance proposal in that SCE sought approval of mandatory TOU but not default
11 CPP. On September 7, 2012, SCE entered into a settlement of its 2012 GRC Phase 2 application with
12 several parties supporting the interests of small commercial customers that reflected an unopposed
13 consensus that small C&I customers should not be transitioned to mandatory TOU rates, and that CPP
14 should remain opt-in. In D.13-03-031, the Commission rejected the settlement agreement provision that
15 CPP would not be the default for small commercial customers. In rejecting the provision, the
16 Commission stated "*we expect that customers in SCE's GS-1 rate group will still be treated in a manner*
17 *broadly consistent with the treatment of [Pacific Gas & Electric Company (PG&E) and San Diego Gas*
18 *and Electric Company (SDG&E)] customers, by following implementation of mandatory TOU with a*
19 *subsequent transition to default CPP rates.*"³¹ In D.21-07-010, the Commission approved SDG&E's
20 proposal to make CPP an opt-in rather than default rate for its small commercial customers.

21 In the spirit of maintaining consistency and based on SCE's experience over the
22 last several years of default CPP, in this Application, SCE now proposes to make CPP an opt-in rather
23 than a default option for its small commercial customers (i.e., customers with less than 20 kW of
24 demand). For the reasons described below, SCE also proposes this change for its medium commercial
25 customers, i.e., those sized between 20 and 200 kW of demand. At a minimum, these changes should be

³¹ D.13-03-031, p. 23.

1 approved for small commercial customers. To further improve the program's efficacy, SCE also
2 proposes changes to CPP that target the hours of greatest need and remove non-performing customers
3 from CPP. In support of the CPP program changes, SCE presents data in the following sections
4 highlighting customer performance (or lack thereof) and the associated administrative program costs
5 which provide clear data in support of the related recommendations.

6 (3) Transition CPP to an Opt-in Enrollment Process for Small Commercial
7 Customers

8 (a) Restore Consistency With Other IOUs' CPP Programs

9 In D.18-07-006, the Commission denied without prejudice SCE's
10 request to offer CPP as an opt-in rather than a default rate to customers on its small commercial and
11 large agricultural rates. The decision stated that the primary reason SCE's proposal was denied was that
12 more analysis was needed to demonstrate the benefits of offering optional CPP as opposed to default
13 CPP. D.18-07-006 also stated that SCE could pursue its request through a petition for modification of
14 that decision so that it could be reconsidered prior to the implementation date. However, given that
15 implementation has long been achieved, SCE now proposes for consideration its changes in this rate
16 design application.

17 In D.21-07-010, the Commission approved SDG&E's proposal to
18 make CPP an opt-in rather than default rate for small commercial customers. Similar to SDG&E, SCE
19 has now had default CPP for small commercial customers and has gained experience and data over the
20 last five years that show CPP as a default rate has not been beneficial or cost effective for the small
21 commercial customer class or for ratepayers in general. To maintain the consistency encouraged by the
22 Commission in D.13-03-031, SCE's proposal to eliminate default CPP for small commercial customers
23 should be adopted.

24 (b) TOU Rates Can Be Simpler and Clearer Signals Than CPP Events
25 for Smaller Commercial Customers

26 One reason that default CPP should be eliminated for small and
27 medium commercial customers is that SCE has mandatory TOU rates for those customers, which

1 already discourage customers from using energy during the 4-9 p.m. on-peak period. CPP may be
2 problematic for small commercial customers for two reasons. First, because CPP events occur during
3 the same 4-9 p.m. period as the TOU on-peak, these commercial customers are likely to already be
4 reducing their usage in response to the TOU signal and may not have discretionary load that they can
5 reduce during CPP events. The combination of these two signals may be confusing for the typically
6 less-sophisticated small and medium commercial customers, leading to inefficient energy usage patterns
7 and potential bill volatility. Most small and medium commercial class customers are small businesses
8 that are typically not as sophisticated as larger C&I customers when it comes to energy usage. SCE
9 posits that the existing TOU rate structure is a better and easier to understand signal for most small and
10 medium commercial customers because it varies based on a regular schedule and does not depend on
11 events that will occur on an unknown day. Second, because CPP credits for these customers are earned
12 through energy usage during these hours on non-event summer days, reducing energy in response to the
13 TOU signal will also reduce the amount of CPP credits they will receive.

14 (c) SCE's CPP Load Impacts Have Significantly Declined Since
15 Implementation of Default Enrollment

16 As illustrated in Figure II-1 above, CPP load impacts (MW) have
17 declined significantly due to the implementation of default enrollment onto CPP. In 2018, prior to
18 implementation of default enrollment and the change in event window from 2 p.m. to 6 p.m. to the
19 current 4 p.m. to 9 p.m., CPP had total ex-ante load impacts of approximately 33 MW.³² At that time,
20 the TOU-GS-1 CPP credit and charge were set at (\$0.038)/kWh and \$1.38/kWh, respectively. The TOU-
21 GS-2 CPP credit and charge were set at (\$10)/kW-month- and \$1.38/kWh. In March 2019, with the
22 change in the CPP event window to 4 p.m. to 9 p.m., SCE began the default CPP enrollment process,
23 enrolling approximately 245,000 customers, most of which were small and medium commercial
24 customers, and the load reduction dropped to about 26 MW³³. In 2023, SCE had approximately 237,000

³² CPP event window was 2-6 p.m. and had over 3,240 enrolled customers, most of whom were large C&I customers.

³³ Represents Ex-Ante data reported in SCE's monthly ILP to the Commission.

1 enrolled customers with an estimated total load impact of approximately 14 MW.³⁴ The MW reduction
2 is due largely to the low per-customer ex ante MW attributed to the non-performing small and medium
3 commercial customers which make up most of CPP enrollments. In summary, due to a combination of
4 the event window changing and default CPP enrollment, the CPP program now provides less than half
5 the MW than it did in 2018, despite significantly more enrolled accounts and a higher credit and lower
6 charge for small and medium commercial customers. Removing default CPP enrollment for small and
7 medium commercial customers would likely result in higher per-customer ex ante load impacts due to a
8 greater proportion of enrolled customers affirmatively opting into the program and responding to CPP
9 events.

10 (d) SCE's CPP is not Cost Effective for SCE or Most Small and
11 Medium Commercial Customers

12 SCE's analysis of costs and benefits for small and medium
13 commercial CPP supports its proposal to transition to opt-in rather than default enrollment. From 2021
14 to 2023, SCE recorded approximately \$64 million per year on average on administrative costs and
15 incentives, approximately \$6 million of which was for small commercial CPP customers and received
16 only 0.01 MW in load impacts from those small commercial CPP customers. Similarly, over the same
17 years SCE recorded approximately \$11 million per year on average on administrative costs and
18 incentives for medium commercial CPP customers and received 1.68 MW. By comparison, SCE's Base
19 Interruptible Program (BIP), which the Commission has deemed a cost-effective supply-side reliability
20 demand response program, recorded approximately \$63 million per year on average and delivered more
21 than 477 MW.³⁵

22 In addition, SCE has observed, both through conversations with
23 customers and data analysis, that most small CPP customers do not financially benefit from the program,
24 and many may not be aware they are enrolled on the rate, despite SCE's outreach efforts. SCE's

³⁴ In the 2018 GRC Phase 2, the small commercial CPP incentive was set to a value of (\$0.13643)/kWh, corresponding to a CPP event charge of \$0.80/kWh.

³⁵ D.23-12-005, Finding of Fact (FOF) Paragraph 51.

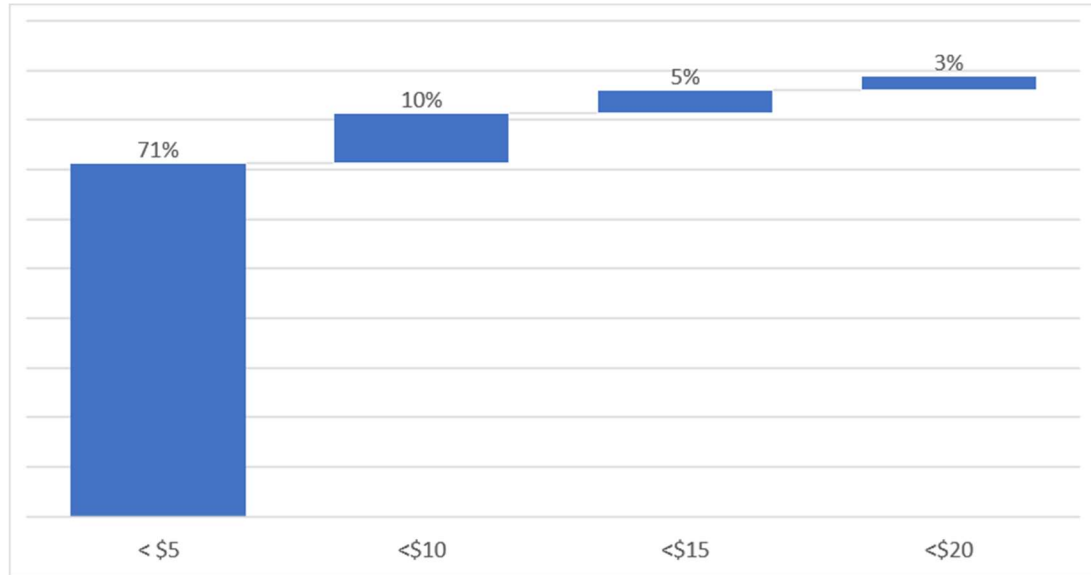
1 analysis, shown in Figure II-2 below, shows approximately 71 percent of small commercial customers
2 enrolled in CPP earned net CPP credit of less than \$5 per year on average between 2021 and 2023, and
3 approximately 89 percent earned a net CPP credit of less than \$20 per year on average between 2021
4 and 2023.³⁶ In addition, between 2021 and 2023 on average, approximately 15 percent of customers
5 earned \$0 and approximately 25 percent had a negative incentive (i.e. customers paid money to be on
6 the rate).³⁷ SCE defines “non-performing customers” for this purpose as those CPP-enrolled customers
7 that receive annual net CPP bill credits totaling less than \$20 for two consecutive years. Given that the
8 CPP incentive is currently \$0.14-per-kWh applied to usage during the non-event CPP hours, a small
9 commercial customer using approximately 150 kWh during these CPP periods each summer would earn
10 \$20 in incentives, assuming no CPP event charges. If the CPP Non-Event Energy Credit factor changes
11 in the future, SCE will revise the CPP non-performance clause³⁸ of its small commercial tariffs to reflect
12 the updated kWh amount necessary to receive \$20 in incentives per year.

³⁶ The 89 percent for those that earned less than \$20 per year includes the 71 percent of customers that earned less than \$5 per year.

³⁷ Incentive amounts provided are net of CPP charges earned in the same period.

³⁸ I.e., a new clause in SCE’s CPP tariff that would be added upon approval of this proposal and updated as necessary when the CPP credit factor changes.

Figure II-2
CPP Incentives Earned by Non-Performers, Shown as a Percentage of Total CPP Customers



SCE sees similar results for the medium commercial customer class. Between 2021 and 2023, 60 percent of medium commercial customers enrolled in CPP earned less than \$5 per year on average, and approximately 62 percent made less than \$20 per year on average. This data shows that the medium commercial customers enrolled in CPP face similar barriers to participation as the small commercial customers. As such, SCE recommends that medium commercial customers also be moved from a default to an opt-in enrollment process and that non-performing medium commercial customers as defined herein also be disenrolled from CPP.

(e) SCE's Proposal

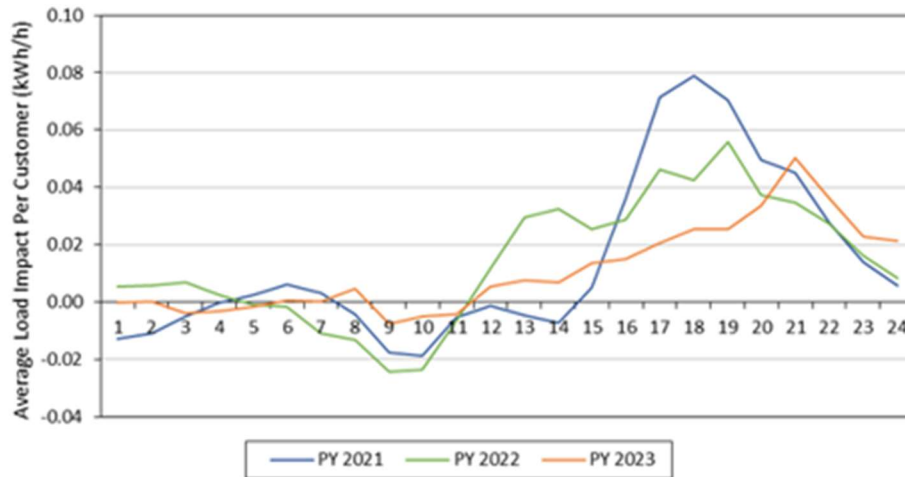
For these reasons, SCE proposes to take the following actions related to CPP participation for small and medium commercial customers: 1) transition from a default to an opt-in enrollment process; and 2) disenroll all non-performing small and medium commercial customers. Upon approval of its proposal, SCE will disenroll non-performing small and medium commercial CPP customers as soon as the required systems changes can be made, ideally prior to Summer 2026.

1 By changing the enrollment process from default to opt-in, SCE
2 expects to save approximately \$477,000 annually for the small commercial class. Additionally, for the
3 medium commercial class, SCE expects to save approximately \$238,000 annually. SCE expects these
4 two changes will also provide non-monetary benefits by allowing customers the choice of whether to
5 participate or not and by increasing the efficacy of CPP by encouraging action to be taken in response to
6 CPP events and increasing the per-customer load impact for CPP, which will make the program more
7 cost-effective. Small and medium commercial customers would still be able to opt-in to CPP if they so
8 desire, and regardless of their CPP participation, their existing TOU rates will incentivize them to
9 consume less electricity during summer on-peak periods.

10 (4) Allow CPP to Focus on the Hours of Highest Need Within the 4 P.M. to 9
11 P.M. Window

12 CPP is intended to address grid constraints or high costs by charging a
13 higher price for energy consumption during CPP events, which occur during the hours that the grid
14 typically experiences highest demand. Currently, once triggered, CPP events last for all five hours of
15 the 4 p.m. to 9 p.m. window. While this window includes the hours when the grid typically sees
16 potential supply shortfalls and high prices, it is not always the case that the grid needs demand response
17 resources for the full five hours. The current CPP tariff requires that each event, of which there are
18 between 12 and 15 per year, last for the full 5-hour window. This results between 60 and 75 hours of
19 CPP events per year, which can be a major commitment for customers, especially if a grid emergency
20 triggers CPP but is resolved after a few hours, as has happened several times. In the 36 CPP events
21 called between 2021 and 2023, only six of them occurred on the same day as CAISO emergencies, and
22 of these six, only three emergencies lasted the full five hours of the 4-9 p.m. window. This provides
23 evidence that CPP is dispatched more than is necessary to support the grid. In addition, as shown in
24 Figure II-3 below, non-residential CPP customer load reduction typically does not remain high for all
25 hours of the CPP event, but typically spikes in one hour and drops steeply before and after that hour.
26 This provides evidence that CPP events are too long for most customers to provide consistent load
27 reduction.

Figure II-3
Average Hourly Ex-Post Load Impact For Non-Residential CPP Customers
2021-2023



SCE expects that a CPP program more tailored to the specific hours of grid need for each event would provide benefits in terms of customer engagement, grid resiliency, and program efficacy. As such, SCE proposes to revise its entire CPP program to allow for 60 hours of events per year³⁹ at three hours per event, resulting in 20 events per year. Events would be called at the discretion of SCE and based on day-ahead forecast data from the CAISO and SCE internal teams. If adopted, SCE would implement this change by Summer 2026.

(5) Remove Non-Performers From CPP Prospectively

To maintain the effectiveness and capacity of the program for small and medium commercial customers, SCE proposes to implement a non-performance clause into the relevant tariffs that would allow SCE to remove a customer from CPP if they do not perform for two consecutive years. “Non-performance” for this purpose would be defined as a customer earning less than \$20 per year in net total CPP incentives, the same definition as proposed to be used for removing currently non-

³⁹ Based on the existing five hours per event multiplied by 12 events per year.

1 performing small and medium commercial CPP customers in Section 1(d) above. For current TOU-GS-
2 1 CPP rates, a customer would need at least 150 kWh during the entire non-event summer on-peak
3 period to earn at least \$20 in CPP bill credits, assuming no CPP event charges. As described above,
4 SCE has identified many small and medium commercial customers on CPP may not be aware that they
5 are on the program, despite SCE's repeated communication on the topic. SCE is currently spending a
6 significant amount of money for little to no load reduction from small and medium commercial CPP
7 customers. It costs SCE approximately \$4 per customer per year to administer the CPP program, not
8 including incentives paid. SCE posits that ratepayers would receive better value for this money if it
9 were focused on higher-performing CPP customers. Removing customers that consistently fail to
10 reduce load during CPP events, whether by choice or because they are unaware they are on the program,
11 will protect these customers from potential bill volatility and high bills when there are CPP events. This
12 change would increase customer satisfaction and support affordability, which is currently an area of
13 focus for the Commission. SCE proposes to implement this change prior to Summer 2026.

14 Additionally, the CPP credit levels (on a dollar-per-kW and cent-per-kWh
15 basis) have been updated to reflect the forecast billing determinants presented herein.⁴⁰ Table II-2
16 illustrates the proposed CPP charges and credits.

⁴⁰ On December 14, 2023, the Commission issued D.23-12-005, which approved DR Programs, Pilots, and Budgets for years 2024-2027. SCE will utilize approved DR incentives when it implements its 2025 GRC Phase 2 authorized changes.

Table II-2
CPP Pricing And Credits

Less than 200 kW (Day-Ahead Program)	
4 p.m. to 9 p.m. Critical Peak Period (CPP) Event	URG Component
<u>Event Energy Charge - \$/kWh</u>	0.80000
<u>Non Event Energy Credit - \$/kWh (Summer On-Peak)</u>	
Domestic	(0.15170)
GS-1 Small Commercial	(0.13643)
<u>Non Event Capacity Credit - \$/kW (Summer On-Peak)</u>	
GS-2 Medium Commercial - \$/kW	(6.85)
TOU-PA-2 - \$/kW	(5.68)
200 kW and Greater (Day-Ahead Program)	
4 p.m. to 9 p.m. Critical Peak Period (CPP) Event	URG Component
<u>Event Energy Charge - \$/kWh</u>	
Secondary	0.80000
Primary	0.80000
Subtransmission	0.80000
<u>Non Event Capacity Credit - \$/kW (Summer On-Peak)</u>	
TOU-GS-3	(7.55)
TOU-8-Secondary	(8.22)
TOU-8-Primary	(8.52)
TOU-8-Subtransmission	(8.44)
TOU-PA-3	(6.18)

b) Interruptible And Air Conditioning Cycling Programs

SCE has approximately 896 service accounts served on interruptible rate schedules (i.e., Schedules TOU-BIP and AP-I) that provide for load reductions to a firm service level in response to events triggered by SCE or the California Independent System Operator (CAISO). SCE also has approximately 163,108 service accounts served on the Summer Discount Plan (SDP) Program,⁴¹ which allows SCE to cycle participating customers' air conditioning systems. Interruptible customers receive a credit in exchange for their agreement to reduce load. The MW capacity these customers make available reduces the need for SCE to procure capacity during hours when conditions will likely cause energy prices to rise significantly or during times in which reliability constraints could likely cause rotating outages.

Table II-3, Table II-4 and Table II-5 illustrate the current credits for the SDP, BIP and AP-I programs as

⁴¹ The SDP program has two associated rate schedules: (1) Schedule D-SDP, *Summer Discount Plan* (Residential SDP), and (2) Schedule GS-APS-E, *General Service – Automatic Power Shift – Enhanced* (Commercial SDP). For simplicity, SCE refers to both programs as SDP throughout this exhibit.

included in October 2023 rates.

Table II-3
Current Summer Discount Plan Program (SDP) Credit Levels

	Current SDP Credit Levels
Residential	
D-SDP (Standard Option)	
Air Conditioning Cycling Credit - \$/ton/summer season day	
50% Cycling	(0.164)
100% Cycling	(0.328)
D-SDP-O (Override Option)	
Air Conditioning Cycling Credit - \$/ton/summer season day	
50% Cycling	(0.083)
100% Cycling	(0.164)
Commercial	
GS-APS-E (Schedules: GS-1 and TOU-GS-1)	
Air Conditioning Cycling Credit - \$/ton/summer season day	
30% Cycling	(0.019)
50% Cycling	(0.095)
100% Cycling	(0.270)
GS-APS-E (Schedules: GS-2, TOU-GS-2, or TOU-8)	
Air Conditioning Cycling Credit - \$/ton/summer season month	
30% Cycling	(0.58)
50% Cycling	(2.90)
100% Cycling	(8.24)

Table II-4
Current Base Interruptible Program (BIP) Credits

S/kW Credit Applicable to TOU Average Demand	Current BIP Credit	
	30-Minute	15-Minute
Service Option		
Secondary Service (below 2kV)		
Summer on-Peak	(23.54)	(26.11)
Summer mid-Peak	(1.84)	(2.04)
Winter mid-Peak	(9.89)	(10.97)
Primary Service (2kV or 50kV)		
Summer on-Peak	(23.14)	(26.11)
Summer mid-Peak	(1.50)	(1.70)
Winter mid-Peak	(9.07)	(10.26)
Subtransmission Service (above 50kV)		
Summer on-Peak	(15.37)	(17.84)
Summer mid-Peak	(0.73)	(0.86)
Winter mid-Peak	(5.54)	(6.46)

Table II-5
Current Agricultural And Pumping Interruptible (API) Program Credits

S/kW Credit Applicable to TOU Average Demand	Current API Credit
Service Option	
TOU-API	
Summer on-Peak	(19.62)
Summer mid-Peak	0.00
Winter mid-Peak	(10.87)

6. Power Factor Adjustment

Power factor is a measure of the electrical efficiency of an electric system. When power factors are low, generation sources must provide higher voltage to deliver the same number of watts, thus consuming more fuel. To improve power factors, SCE must install additional capacitors. The Power Factor Adjustment (PFA) rate is designed to recover the costs of these capacitors and is assessed as a dollar-per-kilovar (kVAR) charge applied to customers' monthly maximum kVAR for the billing period. In previous GRC Phase 2 applications, PFA rates were based on an embedded cost study, with the associated revenue requirement directly assigned to those rate groups responsible for incurring

power factor-related costs. In this Application, SCE scaled the 2021 GRC Phase 2 PFA rate factors at the same inflation index SCE used for Marginal Cost Analysis. SCE took this approach due to differences in how SCE currently records costs associated with additional capacitance and how those costs were previously recorded. The proposed PFA rates are shown in Table II-6.

***Table II-6
Current Power Factor Adjustments***

Service Voltage	Current Monthly Rate \$/kVAR	Proposed Monthly Rate \$/kVAR
Greater than 50 kV Transmission & Subtransmission	0.66	0.76
Less than 50 kV Distribution	0.52	0.60

7. Voltage Discounts And Phase-of-Service

SCE delivers power to its customers at various voltage levels. As discussed in Exhibit SCE-02, SCE's delivery system consists of four voltage levels for the purpose of determining marginal costs, revenue allocation and rate design: transmission (220 kilovolt (kV) and above), subtransmission (above 50 kV but less than 220 kV), primary distribution (from 2 kV to 50 kV), and secondary distribution (below 2kV).

Service at the transmission level is generally reserved for very large customers, such as wholesale customers. Most of SCE's customers take power delivery at the secondary distribution voltage level, and a relatively small number of large customers take power delivery at the primary distribution and subtransmission voltage levels.

SCE's customers with demands of 500 kW or more are split into three separate rate groups that are defined by delivery voltage levels. As a result, variations in SCE's cost of service resulting from differences in delivery voltage are captured in the revenue allocation process and reflected in the rate design for each large power rate group. All other rate groups also include customers who take power delivery at different voltages. For example, although most customers in the TOU-GS-2

1 rate group are served at the secondary distribution voltage level, a small percentage (less than one
2 percent) take power delivery at the primary distribution voltage level, and a few customers take service
3 at the subtransmission voltage level. For these rate groups, rates are designed to recover the costs of
4 delivering power at the predominant voltage delivery level, *i.e.*, the secondary distribution voltage level.
5 As the cost of service varies at different voltage levels based on customers' use of the delivery system,
6 adjustments to rate components must be made for customers who take delivery at service voltages that
7 differ from the typical service voltage for the consumer group to which they belong.⁴² Differences in the
8 cost of service at different voltage levels also reflect differences in line losses at different voltage levels
9 along the delivery system.

10 a) Distribution Voltage Discounts

11 To account for differences in customers' use of the distribution infrastructure
12 when served at different voltage levels, SCE applies a voltage discount to the distribution demand
13 charges for demand-metered schedules such as TOU-GS-2 or TOU-GS-3. Service voltage cost
14 differences for non-demand-metered schedules reflect a voltage discount to the distribution energy
15 charges. SCE also reflects demand line losses for service at higher voltage levels as a discount applied
16 to the distribution demand charges or to the distribution energy charges, depending on the rate schedule.
17 Table II-7 provides a comparison of present and proposed distribution voltage discounts.
18

⁴² Voltage discounts account for the fact that customers served at the secondary distribution voltage level access more of the delivery system than customers served at primary distribution and subtransmission voltage levels. As such, customers served at either primary or subtransmission service voltage levels receive lower distribution charges relative to customers served at the secondary service voltage level.

Table II-7
Present And Proposed Distribution Voltage Discounts
By Rate Group Demand/Distribution Energy
(\$/kW, \$/kWh)

Facilities Related Demand - Distribution (\$/kW)				
Rate Group	Primary		Subtransmission	
	Current	Proposed	Current	Proposed
TOU-GS-1	-	-	-	-
TOU-GS-2	0.33	0.30	7.21	6.24
TOU-GS-3	0.28	0.37	6.10	7.50
TOU-PA-2	0.14	0.21	2.99	3.97
TOU-PA-3	0.21	0.31	4.24	6.01

Summer Time Related Demand - Distribution (\$/kW)				
Rate Group	Primary		Subtransmission	
	Current	Proposed	Current	Proposed
TOU-GS-1	-	-	-	-
TOU-GS-2	0.27	0.25	5.12	3.48
TOU-GS-3	0.27	0.28	5.08	3.83
TOU-PA-2	0.06	0.08	1.11	1.05
TOU-PA-3	0.07	0.09	1.34	1.30

Winter Time Related Demand - Distribution (\$/kW)				
Rate Group	Primary		Subtransmission	
	Current	Proposed	Current	Proposed
TOU-GS-1	-	-	-	-
TOU-GS-2	0.27	0.07	5.12	0.91
TOU-GS-3	0.27	0.07	5.08	1.02
TOU-PA-2	0.00	0.00	0.00	0.00
TOU-PA-3	0.07	0.00	1.34	0.00

Distribution Energy (\$/kWh)				
Rate Group	Primary		Subtransmission	
	Current	Proposed	Current	Proposed
TOU-GS-1	0.00130	0.00166	0.02653	0.02934
TOU-GS-2	0.00027	0.00029	0.00029	0.00405
TOU-GS-3	0.00022	0.00024	0.00415	0.00329
TOU-PA-2	0.00026	0.00032	0.00482	0.00450
TOU-PA-3	0.00023	0.00028	0.00419	0.00392

(1) Generation Voltage Discounts

SCE reflects the difference in generation energy and capacity costs for various voltage levels as a percentage discount to the generation component of the generation demand charge or to the generation energy charges, depending on the rate schedule. Differences in energy line losses are reflected as discounts to the generation energy rates for all schedules. Appendix D provides the computations of the various discounts. Table II-8 compares present and proposed generation voltage discounts for demand losses. Table II-9 compares present and proposed generation voltage discounts for energy losses.

Table II-8
Present And Proposed Generation Capacity Voltage Discounts
(\$/kW)

Generation Summer Time Related Demand (\$/kW)				
Rate Group	Primary		Subtransmission	
	Current	Proposed	Current	Proposed
TOU-GS-1	-	-	-	-
TOU-GS-2	0.65	0.27	1.50	0.62
TOU-GS-3	0.57	0.30	1.31	0.70
TOU-PA-2	0.21	0.23	0.48	0.54
TOU-PA-3	0.26	0.32	0.60	0.74

Generation Winter Time Related Demand (\$/kW)				
Rate Group	Primary		Subtransmission	
	Current	Proposed	Current	Proposed
TOU-GS-1	-	-	-	-
TOU-GS-2	0.65	0.11	1.50	0.24
TOU-GS-3	0.57	0.13	1.31	0.29
TOU-PA-2	0.00	0.11	0	0.25
TOU-PA-3	0.26	0.15	0.60	0.34

Table II-9
Present And Proposed Generation Energy Voltage Discounts
(\$/kWh)

Rate Group	Generation Energy (\$/kWh)			
	Primary		Subtransmission	
	Current	Proposed	Current	Proposed
TOU-GS-1	0.00180	0.00163	0.00393	0.00353
TOU-GS-2	0.00128	0.00132	0.00280	0.00286
TOU-GS-3	0.00128	0.00132	0.00279	0.00286
TOU-PA-2	0.00130	0.00134	0.00286	0.00290
TOU-PA-3	0.00129	0.00134	0.00282	0.00289

(2) Seasonality Changes to Voltage Discounts

Consistent with the seasonality in time related energy and demand charges, SCE proposes to implement seasonal service voltage discounts for TOU-GS-1, TOU-PA-2, and TOU-PA-3 (the current voltage discount for these rate schedules is not differentiated by season). The summer voltage discount will be applied to the summer on-peak period and the winter voltage discount will be applied to the winter mid-peak period, consistent with the way TRD charges are assessed on the underlying retail rate.⁴³

(3) Single- and Three-Phase Service Adjustments

SCE proposes separate single-phase and three-phase customer charges in the TOU-GS-1 and TOU-GS-2 rates schedules based on working group discussions conducted in the attrition year study. As an outcome of Residential and Small Commercial Rate Design Settlement Agreement, in Phase 2 of SCE's 2021 GRC that was eventually adopted in Commission Decision D.22-08-001, SCE was required to perform a study to assess the feasibility and customer bill impacts resulting from a suite of agreed upon scope elements identified for the Study: 1) Modification of the existing 20 kilowatt (kW) monthly maximum demand for the TOU-GS-1 rate group; 2) Reclassification or consolidation of the TOU-GS-1 and TOU-GS-2 rate groups into a single rate group; and 3) Migration of

⁴³ In SCE's 2021 GRC Phase 2 proceeding, Settling Parties for Medium and Large Power Rates agreed to differentiate the voltage discount into seasonal service voltage discounts for all rate options. SCE implemented these changes for TOU-GS-2 and TOU-GS-3, as TOU-8 and Standby rate classes.

1 existing lighting load on TOU-GS-1 rate schedules to other applicable lighting rate schedules or a new
2 lighting and common services rate schedule. Pursuant to the Settlement Agreement, the study results
3 were to be presented in the 2022 RDW Application. In June 2022, SCE initiated a working group
4 consisting of SCE, the California Farm Bureau Federation (CFBF), the Public Advocates Office at the
5 Commission (Cal Advocates), the Small Business Utility Advocates (SBUA), and The Utility Reform
6 Network (TURN). The study results led SCE to make the following conclusions with respect to the
7 reclassification of customers and customer charges:

8 1) The existing small and medium General Service rate class definitions should
9 be maintained at:

- 10 a. TOU-GS-1 (Monthly demands of 20 kW and less)
- 11 b. TOU-GS-2 (Monthly demands of 21 kW up to 199 kW)

12 2) In its 2025 GRC Phase 2 Proceeding, SCE will propose phase-differentiated
13 customer charges within these respective rate classes that reflect the cost of customer service at single-
14 phase or three-phase.

15 When the working group explored reclassification and the effect of customer
16 charges through various rate design scenarios, the bill impacts demonstrated “that the levels of customer
17 charges had an overwhelming impact on bills and average rates for both customer groups— more so
18 than the classification of customers within the current definition of the respective classes.” SCE
19 ultimately concluded, and working group parties agreed, that the current group classification of TOU-
20 GS-1 and TOU-GS-2 were appropriate⁴⁴. The working group then concluded that a more granular
21 design of customer charges, one that differentiated between single- and three-phase service based on
22 marginal costs differences would result in greater intra-class equity for the respective rate classes.

23 SCE’s current rates adjust the customer charge for customers on TOU-GS-1 and
24 TOU-GS-2 rate schedules based on single-phase or three-phase service and attempt to reflect the cost of
25 the customer access and the costs of ongoing retail billing and customer engagement. For the TOU-GS-

⁴⁴ A.22-12-004, Exhibit SCE-01, p. 5.

1 1 rate group, mainly composed of single-phase customers, SCE applies a surcharge for customers within
2 the group that receive three-phase service. In contrast, customers in the TOU-GS-2 rate group who
3 receive single-phase service are currently provided a discount through a surcredit as the default customer
4 charge for TOU-GS-2 customers assumes three-phase service. In this proceeding, SCE proposes to
5 continue applying the surcharge and surcredit to the default customer charge in each respective
6 consumer group but makes changes to how the default customer charge will now be set based on the
7 typical phase of service for the group: single-phase for TOU-GS-1, and three phase for TOU-GS-2. The
8 surcharge and surcredit are based on the equal-percent-marginal-cost difference between single phase
9 and three phase service customer charges after accounting for any rate design elements generally
10 adopted in setting the default customer charge for the respective rate group. Appendix B illustrates the
11 default customer charges for the TOU-GS-1 and TOU-GS-2 rate groups, in addition to the surcharge and
12 surcredit for the alternative service in each consumer group.

13 **C. Optional Non-Residential Rate Structures** ⁴⁵

14 **1. Option-E**

15 Consistent with SCE's vision of a clean energy future, SCE designs Option-E rates based
16 on the same underlying marginal costs discussed in SCE-02, but moderates pricing so that customers can
17 harvest flexible load in a manner that reduces utility costs over the long-run, while also contributing to
18 the State's goals on GHG reduction.

19 The Option-E rate structure recovers time-variant capacity cost revenues through a
20 combination of time-differentiated energy and time-differentiated demand charges. As discussed in
21 Section II.B.3, for Option-E rates, generation capacity costs are added to the generation energy costs and
22 recovered through TOU cent-per-kWh energy charges.

23 For the medium and large power rate groups, a portion of generation capacity costs is
24 recovered through time-differentiated demand charges on a dollar-per-kW basis. Generally, Option E
25 rates reflect lower demand charges, relative to Option D, by recovering a portion of capacity cost

⁴⁵ SCE's optional residential rate proposals are in Section III. Other rate proposals specific to certain rate groups are included in Sections IV through VII, below.

1 revenues through energy charges. Doing so enables customers to harvest the time sensitive nature of
2 their load while responding to a moderate blend of energy, time-dependent demand, and non-time-
3 dependent demand charges. Appendix G provides a schematic illustration of the relative recovery of
4 distribution and generation related capacity revenues designed in Option-E rates for each rate/consumer
5 group. All other charges (*e.g.*, NBCs, transmission, kVAR, etc.) are recovered in the same way as the
6 default, Option-D rate schedule.

7 For large power rate groups, SCE’s 2021 GRC Phase 2 settlement agreement retained
8 technology-based eligibility requirements and caps participation of customers adopting DER
9 technologies under the Option-E rate schedule to 250 MW – the MW capacity being the system’s
10 alternating current (AC) nameplate rating.⁴⁶ The settlement agreement also required SCE to file an
11 information-only Advice Letter (AL) to report on the progress towards the 250 MW cap, with
12 the frequency of the ALs being one for every 50 MW of installed capacity until 250 MW is reached. As
13 of February 29, 2024, the installed capacity for customers who have DER technologies and subscribe to
14 Option-E is 59.3 MW. Because participation under the Large Power Option-E cap remains significantly
15 below the target (23.7 percent of the allowable capacity), in this Application, SCE proposes to retain
16 both eligibility requirements and participation caps for large power Option-E customers.

17 **2. Option S-Like Tariff for Commercial Storage Applications**

18 During the 2021 GRC Phase 2 proceeding, SEIA proposed a new rate option “S” that
19 “would start with the design of [the current] Option E rates, except that the noncoincident demand
20 charge for distribution costs is converted into a daily coincident peak demand charge, applicable during
21 SCE’s on- and mid-peak periods and designed to recover the same revenues as the existing monthly
22 noncoincident distribution demand charge.⁴⁷” SEIA’s argument for establishment of an Option S rate
23 included supposed consistency across utilities, as the Commission had adopted an Option S for PG&E in
24 D.18-08-013, and the noted intent that SEIA’s proposal for an Option S design enabled a more efficient
25 dispatch of behind-the-meter storage resources. SCE argued that the Commission had previously found

⁴⁶ D.18-11-027, p. 36. *See also* Medium and Large Power Rate Group Settlement Agreement, pp. 20-21.

⁴⁷ A.20-10-012, 2021 GRC Phase 2 Proceeding, SEIA Direct Testimony, SEIA-01, at p. 30.

1 Option-E to be just and reasonable for DERs, and that rate options from one utility could not just be cut
2 and pasted to another utility. The Commission rejected Option S but directed SCE “to include a fully
3 analyzed proposal for an Option S-like tariff in its next Phase 2 of the GRC,” regardless of whether SCE
4 proposes an Option S-like tariff.⁴⁸

5 In this Application, in keeping with the spirit and purpose of an Option-S like rate as
6 SEIA proposed, SCE started with the underlying Option-E rate structure by setting the FRD level based
7 on the Option E FRD less the Equal Percent Marginal Costs (EPMC)⁴⁹ portion of allocated revenues.
8 The time-of-use daily demand charge is set to recover the EPMC portion of Option E FRD allocated
9 revenues, and the summer-on and winter-mid distribution revenues recovered in energy rates.
10 Residually, the remaining distribution revenues are recovered through TOU energy charges by retaining
11 the current TOU ratios of the Option E distribution energy rates. No changes were made to the
12 generation portion of the Option E rate structure. Table II-10 illustrates both SCE’s interpretation of
13 SEIA’s design and SCE’s preferred design for an Option S like rate for the TOU-8-SEC rate group – for
14 reference and comparison, SCE also presents proposed Option-E rate, EPMC Scaled Marginal Cost
15 Rate, and the unscaled Marginal Cost rates based on marginal costs and revenue allocation discussed in
16 Exhibit SCE-02 and SCE-03 respectively.

17 SCE does not support SEIA’s structural design for an Option-S like rate where all design
18 demand distribution revenues are only recovered through time-dependent energy and demand charges
19 with no revenue recovery assigned to FRD charges. While SCE acknowledges the potential efficacy of
20 a structural rate design element like time-dependent daily demand charges, having the appropriate blend
21 of time-dependent demand/energy charges that are complemented by non-time dependent demand
22 charges is important to ensure the right balance of overall demand management by customers. Because
23 behind-the-meter storage resources can be flexibly dispatched, SCE presents an Option S that
24 significantly discounts the FRD portion of revenue recovery compared to the marginal cost rate –

⁴⁸ D.22-10-022, p. 18.

⁴⁹ Removal of the EPMC portion of allocated revenues results in an effective grid marginal cost rate. SCE took this approach to account for Option E grid related cost being recovered through a combination of an FRD charge and energy charges.

Introducing such deep discounts can exaggerate cost-shifts over the long-run if customers do not optimize their load response in a manner that complements the intended purpose of the rate. Aside from the structural design elements discussed here, SCE also notes that a rate structure with time-dependent daily demand charges will require changes to SCE 's billing system and interval data management system because *daily demand* is not currently used as a determinant when billing retail customers.

Table II-10
Illustrative Option S Rate Designs

	Proposed E	Illustrative Total Rates - TOU-8-SEC (\$)			
		SEIA's (\$ Rate Design	SCE's (\$ Rate Design	Unscaled Marginal Cost	Scaled Marginal Cost
Customer charge - \$/month	\$1,641.00	\$1,641.00	\$1,641.00	\$1,012.41	\$1,641.00
Summer season					
On-peak - \$/kWh	0.52738	0.52738	0.44397	0.09746	0.16128
Mid-peak \$/kWh	0.26491	0.26491	0.21976	0.08682	0.14036
Off-peak \$/kWh	0.18939	0.18939	0.16636	0.08233	0.13152
On-peak - \$/kW-month	3.71	3.71	3.71	12.75	23.48
Mid-peak - \$/kW-month				1.39	2.38
Off-peak - \$/kW-month				6.72	11.45
On-peak daily demand charge - \$/kW-day		0.45	1.04		
Winter season					
Mid-peak - \$/kWh	0.22727	0.22727	0.22113	0.09006	0.14673
Off-peak \$/kWh	0.15276	0.15276	0.14999	0.08792	0.14251
SOff-peak \$/kWh	0.12347	0.12347	0.11711	0.06630	0.10001
Mid-peak - \$/kW-month	1.62	1.62	1.62	4.03	7.76
Off-peak - \$/kW-month				0.28	0.47
SOff-peak - \$/kW-month				0.94	1.59
Mid-peak daily demand charge - \$/kW-day		0.47	0.32		
Non-coincident peak demand charge - \$/kW-month					
Transmission	5.61	5.61	5.61	5.61	5.61
Distribution	7.00	0.00	4.15	8.45	14.25
Max kVar charge - \$/kVar-month	0.60	0.60	0.60	0.60	0.60

3. Extension of Phase-in of Demand Charges for TOU-EV-8 and TOU-EV-9

SCE proposes an extension to delay the phasing in of demand charges, which would continue the energy-only rate structure of TOU-EV-8 and TOU-EV-9 rate schedules. Proposed energy-only rates reflect updates to marginal costs and revenue allocations discussed in Exhibit SCE-02 and Exhibit SCE-03 respectively. SCE proposes continuing the energy-only rate structure, through the end of 2029, with a five-year gradual phase-in of demand charges beginning on January 1, 2030. Given the confluence of exogenous factors and evolving market conditions, extending the energy-only rate structure is the most prudent path forward. In compliance with the 2021 GRC Final Decision, in Table II-11 and Table II-12, SCE presents both the energy-only rates and the corresponding demand charge rates over the prospective demand charge phase-in period. Rates presented in the table below reflect

updates to marginal costs and revenue allocations discussed in Exhibit SCE-02 and Exhibit SCE-03 respectively and do not account for changes to SCE's revenue requirements that may be authorized between the date of this Application and the effective date of rates adopted in this proceeding. The illustrative rates shown in the tables below phase-in distribution and transmission demand charges, with distribution demand charges reaching the Option-E demand charge levels in Year 6, and transmission demand charges reaching 70 percent of the default transmission demand charge of the respective rate/consumer group in Year 6 – the 70 percent Transmission Demand Charge level shown in the illustrative rates below is a proxy for the 70/30 split for Transmission retail rate design adopted in the Stipulation.

Table II-11
Illustrative Phase-In of Demand Charges – TOU-EV-8

	Energy only Structure	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Customer charge - \$/month	\$140.00	\$140.00	\$140.00	\$140.00	\$140.00	\$140.00	\$140.00
Summer season							
On-peak - \$/kWh	0.67126	0.66659	0.66070	0.65482	0.64894	0.64305	0.63717
Mid-peak \$/kWh	0.32761	0.32294	0.31706	0.31117	0.30529	0.29941	0.29352
Off-peak \$/kWh	0.24941	0.24474	0.23886	0.23297	0.22709	0.22121	0.21533
Winter season							
Mid-peak \$/kWh	0.27957	0.26902	0.26314	0.25725	0.25137	0.24549	0.24549
Off-peak \$/kWh	0.19743	0.18687	0.18099	0.17511	0.16923	0.16334	0.16334
SOff-peak \$/kWh	0.17000	0.15944	0.15356	0.14768	0.14179	0.13591	0.13591
Non-coincident peak demand charge - \$/kW-month							
Transmission	0.00	\$0.56	\$1.12	\$1.68	\$2.24	\$2.80	\$3.36
Distribution	0.00	\$1.13	\$2.27	\$3.40	\$4.53	\$5.66	\$6.80
Max kVar charge - \$/kVar-month							

Table II-12
Illustrative Phase-In of Demand Charges – TOU-EV-9 Secondary

	Energy only Structure	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Customer charge - \$/month	\$1,641.00	\$1,641.00	\$1,641.00	\$1,641.00	\$1,641.00	\$1,641.00	\$1,641.00
Summer season							
On-peak - \$/kWh	0.61220	0.60844	0.60369	0.59895	0.59420	0.58946	0.58471
Mid-peak \$/kWh	0.29755	0.29379	0.28905	0.28430	0.27955	0.27481	0.27006
Off-peak \$/kWh	0.22203	0.21827	0.21352	0.20878	0.20403	0.19928	0.19454
Winter season							
Mid-peak \$/kWh	0.27802	0.27426	0.26952	0.26477	0.26003	0.25528	0.25053
Off-peak \$/kWh	0.18540	0.18164	0.17690	0.17215	0.16741	0.16266	0.15792
SOff-peak \$/kWh	0.15610	0.15234	0.14760	0.14285	0.13811	0.13336	0.12862
Non-coincident peak demand charge - \$/kW-month							
Transmission	0.00	\$0.65	\$1.31	\$1.96	\$2.62	\$3.27	\$3.93
Distribution	0.00	\$1.17	\$2.33	\$3.50	\$4.67	\$5.84	\$7.00
Max kVar charge - \$/kVar-month	0.60	0.60	0.60	0.60	0.60	0.60	0.60

a) Background

In D.18-05-040, the Commission approved SCE’s proposal to delay introduction of demand charges with modifications agreed to by settling parties in the Joint Stipulation.⁵⁰ In the Joint Stipulation, the settling parties agreed to a ten-year term that consisted of a five-year introductory period with no demand charges (March 2019 through March 2024), followed by a five-year phase in of demand charges (March 2024 through March 2029). Subsequently, in D.22-08-001, the Commission approved the Medium and Large Power Rate Design Settlement Agreement, where settling parties agreed to extend the current energy-only rate structure for TOU-EV-8 and TOU-EV-9 beyond the five-year timeline established by D.18-05-040. D.22-08-001 granted the extension until any one of the following rate-making proceedings, whichever occurred first: (1) The implementation of rates adopted in the Phase 2 of the 2025 GRC; (2) A Rate Design Window that would have included any rates guidance in the then on-going Transportation Electrification Framework; or (3) A separate rate design proceeding as determined by the Commission. The commission also stated that if the energy-only structure remained in effect at the time SCE filed its next GRC Phase 2, then SCE should propose to “*begin a gradual phase-in of demand charges that is consistent with the phase-in process outlined in the Joint Stipulation as approved in D.18-05-040 or propose rate structure updates for TOU-EV-8 and TOU-EV-9 that address how demand charges should be implemented*”⁵¹. D.22-08-001 also approved the energy-only

⁵⁰ See Joint Exhibit 12, Stipulation Between SCE, ORA, NRDC, EDF, Siemens, Sierra Club, and CUE.

⁵¹ See Motion of SCE and Settling Parties for Adoption of Medium and Large Power Rate Group Rate Design Settlement Agreement, Attachment A, p. 29.

1 rate structure to be applicable to Direct Current Fast Charger (DCFC) to provide stability to the
2 developing DCFC industry and in this Application, SCE’s proposal also extends to DCFC customers.

3 b) Discussion

4 Although progress has been made in adoption of EVs, SCE believes it is
5 appropriate to delay phasing in demand charges for TOU-EV-8 and TOU-EV-9 to allow time for more
6 maturity in the EV market. Since 2020, a confluence of events ranging from the global pandemic to
7 more recent disruptions in supply chains caused by geopolitical events has extended the timeline for EV
8 adoption and delayed the maturity of the EV market and the industry in general. As discussed below,
9 extending the timing to phase-in demand charges also acts as a complement to the regulatory support
10 that the EV market in California, particularly high-power charging locations, continues to receive from
11 various State agencies.

12 (1) Industry Trends

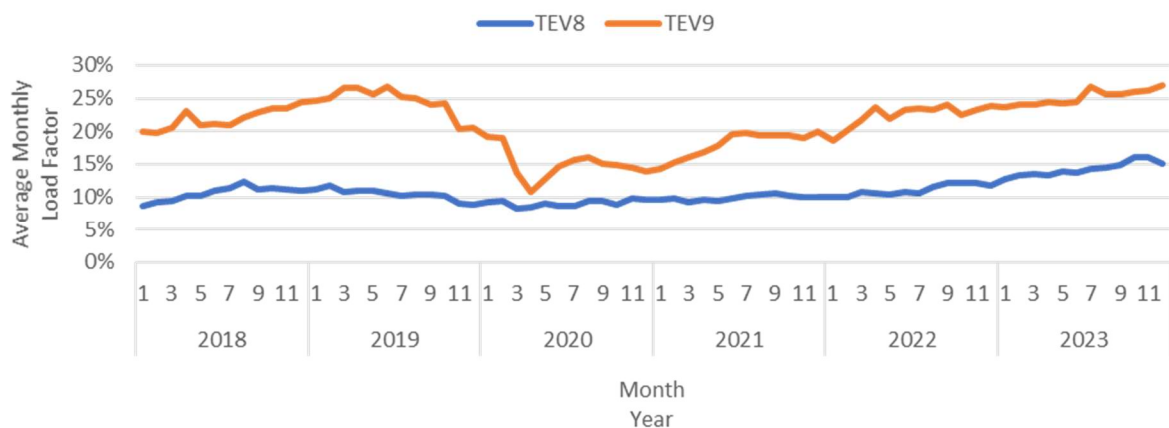
13 The decision to delay the phase-in of demand charges until January 1,
14 2030, is supported by various operational challenges across different sectors. As noted in a publication
15 by the Mason Public Utility District in 2023, in the light-duty (LD) segment, “supply chain disruptions,
16 unpredictable lead times, and unexpected price spikes of common materials has resulted in insufficient
17 charging infrastructure compared to previous projects”.⁵² Accelerating the deployment of charging
18 infrastructure that can be coupled with favorable charging programs and/or pricing structures presents a
19 material opportunity that can help alleviate concerns around expensive LD charging deployment and
20 infrastructure cost, while maintaining the current tailwind that has enabled broader and more equitable
21 EV adoption in SCE’s service territory. In the medium-duty (MD) and heavy-duty (HD) sectors, the
22 lower-than-expected volume of commercial trucking activities significantly impacts charging site
23 utilization for service and infrastructure providers.⁵³ Without the anticipated charging demand, that

⁵² *ALERT: Material Shortages and Supply Chain Crisis Causing Delays*, MASON PUD 3, May 31, 2023; available at <https://www.pud3.org/blog/articles--blog/pud-3-news-releases/alert-material-shortages-and-supply-chain-crisis-causing-delays>.

⁵³ *Electric Trucks Should Shake Off Setbacks In 2024*, Freight Waves; January 3, 2024; available at [Electric trucks should shake off setbacks in 2024 - FreightWaves](#).

benefits host and/or site utilization, phasing in demand charges with the implementation of this GRC would act as a headwind for an ecosystem that continues to grapple with exogenous constraints. The continued effects of the COVID-19 pandemic and the unforeseen disruptions to supply chains have slowed the time-to-market for OEMs and have had a ripple effect on the broader adoption of EVs by customers. When originally stipulated, the initial phase-in of demand charges did not anticipate the global disruption caused by the pandemic, supply chain disruptions, macroeconomic changes stemming from geopolitical hotspots, the surge in domestic inflation, or the increase in interest rates triggered by the Federal Reserve; all of which have had and continue to have a material impact on the market. Figure II-4 shows that the Average Monthly Load Factors took about two years to sustain at the level reached before the pandemic. Postponing the phase-in of demand charges will therefore allow customers the much-needed time to continue addressing operational issues and ensure a smoother transition to more mature site utilization.

Figure II-4
Average Monthly Load Factor by Rate Group



(2) Regulations in California emphasize that DCFC segment will continue to need support over the next few years.

The regulatory rationale for delaying the phase-in of demand charges until January 1, 2030, is consistent with policy that continues to receive regulatory support from the

1 California Air Resources Board (CARB). Specifically, the incentives available for the deployment of
2 public Light Duty (LD) Direct Current Fast Charging and shared-private Medium- and Heavy-Duty Fast
3 Charging infrastructure proposed by CARB, in the 2024 draft amendments to the Low Carbon Fuel
4 Standard (LCFS), present a logical parallel to the proposed extension of phasing in demand charges⁵⁴ by
5 supporting financial incentives for charging locations that have not reached a mature operating state.
6 Under the DC Fast Charging Infrastructure⁵⁵ (FCI) and DC Medium- and Heavy-Duty Fast Charging
7 Infrastructure⁵⁶ (MHD-FCI) pathways established by CARB, station operators receive LCFS credits
8 simply for deploying charging station infrastructure. Unlike other LCFS credits – which are generated
9 by a charging station operator for dispensing electricity as a transportation fuel⁵⁷ – FCI credits provide a
10 financial support mechanism for charging station operators while their operations develop and phases
11 out as they increase their kWh throughput. Demand charges act similarly by decreasing the marginal
12 cost of charging as sites increase their kWh throughput. Stations that provide charging for LD vehicles
13 may apply for a FCI pathway through 2025, while MHD locations would be allowed to apply to receive
14 FCI credits through 2030 under the proposed amendments to the LCFS regulation. Site operators are
15 permitted to claim these capacity credits for up to 5 or 10 years, depending on the category. The LCFS
16 would allow any MHD charging station provider to apply to participate in this development mechanism
17 – the MHD-FCI pathway – until 2030, and then would allow credits to be claimed by that site operator
18 until 2035-2040, or until the limits of their FCI Pathway application; this also parallels SCE’s
19 recommendation for delaying the transition of the public and MHD charging market segments’ pricing
20 structure with demand charges. This alignment of timelines across the framework of CARB’s
21 regulatory stipulations with the CPUC’s own regulatory and policy support adds additional context for
22 why a delay in phasing-in demand charges is needed for a market that will continue to grow and mature

⁵⁴ CEC Staff Report: Assembly Bill 2127 Electric Vehicle Charging Infrastructure Assessment

⁵⁵ Cal. Code Regs. Tit. 17, § 95486.2(b) (2019) - Low Carbon Fuel Standard Regulation, ww2.
arb.ca.gov/sites/default/files/2020-07/2020_lcfs_fro_oal-approved_unofficial_06302020.pdf.

⁵⁶ Appendix A-2 Proposed Amendments to the Low Carbon Fuel Standard Regulation §95486.3(b), ww2.
arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/appa-2.pdf.

⁵⁷ Low Carbon Fuel Standard Regulation §95486.1, ww2.arb.ca.gov/sites/default/files/2020-
07/2020_lcfs_fro_oal-approved_unofficial_06302020.pdf.

1 through 2030. This approach presents a more coherent framework during this transition period that
2 ultimately facilitates the effective integration of pricing structures within the broader regulatory
3 landscape.

4 Operational challenges, market dynamics, and regulatory policies for the
5 EV industry point to a logical need in delaying transitioning these market segments to pricing structures
6 with demand charges. This request for an extension considers the various factors described above and
7 aims to phase-in demand charges at a time when SCE believes the market can reach a degree of maturity
8 that permits an appropriate balance of energy and demand charges for these rate schedules. SCE's
9 proposal is expected to further support the growth of EV adoption, rather than hinder it, and more
10 importantly, dovetail California's policy efforts to decarbonize the transportation sector on its pathway
11 to carbon neutrality.

12 (3) Data and market dynamics show that utilization of EV charging stations
13 has yet to mature.

14 As site utilization and load factors improve, the energy-only rates for
15 TOU-EV-8 and TOU-EV-9 rate schedules act counter to the benefits of demand rates that reduce the
16 marginal cost of charging as each site increases its energy throughput. As illustrated in Figure II-5
17 below, for customers on TOU-EV-8, the Option-E and Option-D rate become more advantageous at an
18 average annual load factor of between 35 percent to 40 percent. Similarly, as shown in Figure II-6
19 below, for customers on TOU-EV-9, the Option-E and Option-D rate become more advantageous at an
20 average annual load factor of between 35 percent to 40 percent. Given these thresholds, SCE's request
21 for delaying a phase-in of demand charges allows customers the much-needed time to improve energy
22 throughput of their charging sites.

Figure II-5
TOU-EV-8 Annual Bill Discount Relative to OAT Options

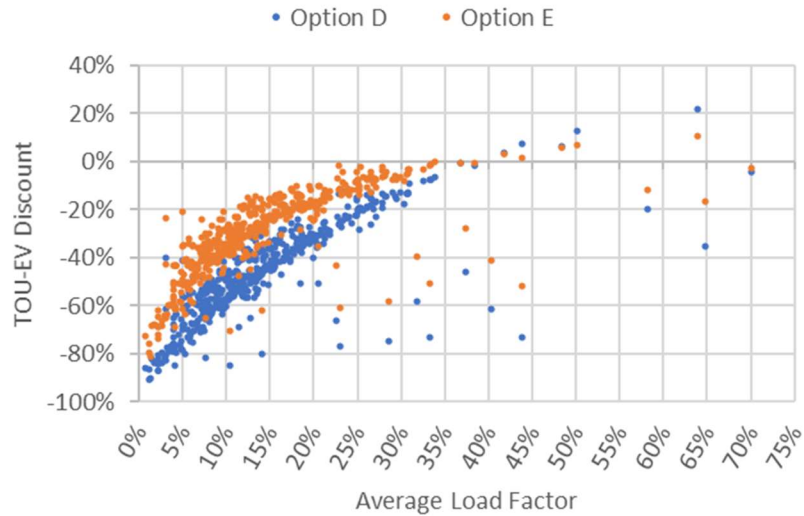


Figure II-6
TOU-EV-9 Annual Bill Discount Relative to OAT Options

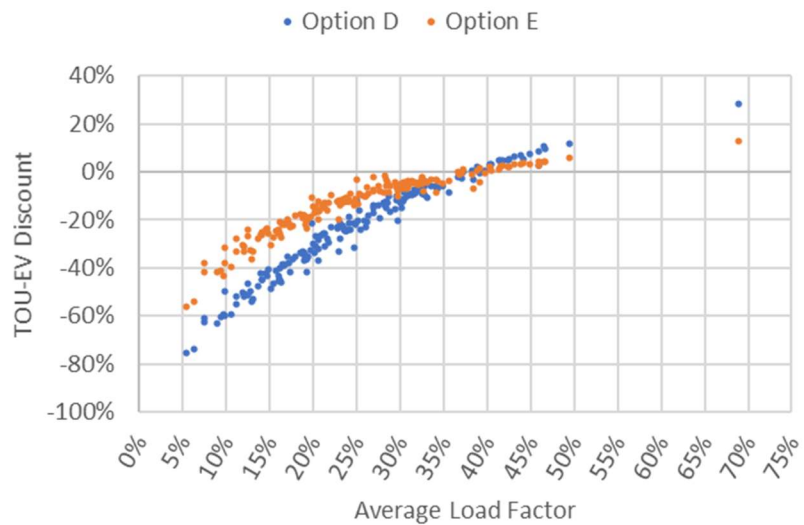
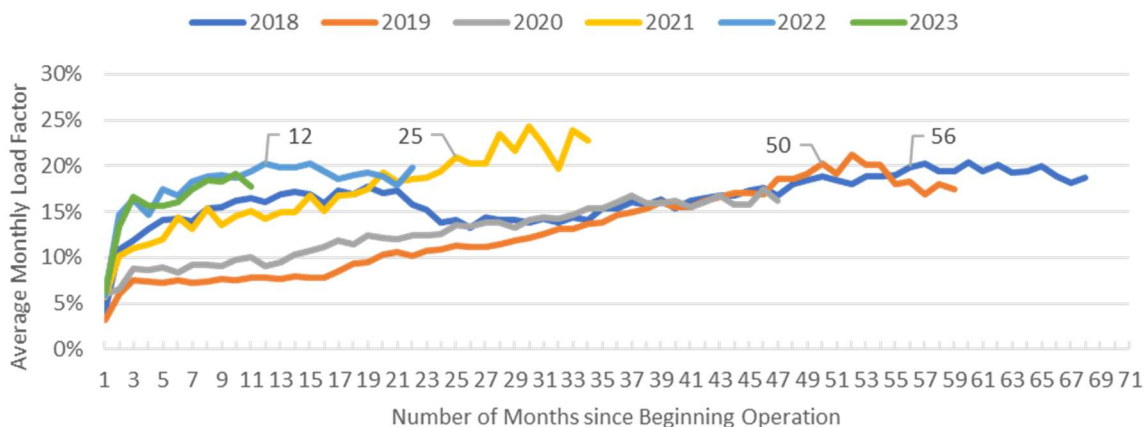


Figure II-7 below SCE illustrates the time a new charging site typically takes to reach the pre-defined load factor threshold of 20 percent - SCE picked 20 percent to draw on a

suitable comparison of load factor maturity across all years shown in the figure. On average, a new charging site opened in 2018 took 53 months (about four and a half years) to reach an average load factor of 20 percent. In 2022 a new charging site took only 12 months (about one year) to reach that same average load factor of 20 percent. While the 20 percent threshold used here for illustrative purposes is still distant from the approximately 40 percent average load factor that results in demand charge rates lowering the marginal cost of charging, the material improvement in time to reach equivalent levels of average load factor points to how much progress the EV market continues to make in improving utilization and energy throughput at charging sites.

Figure II-7
Accelerating Load Factor Improvement for DCFC



With improving site utilization and load factors, demand rates reduce the marginal cost of charging and the customers' effective average rate, thereby boosting the relative competitiveness of EV charging with gasoline. Using customer loads from 2023, and rates in effect as of January 2024, SCE calculated the customer annual electric bill and converted those bills into an equivalent dollar-per-gallon of gasoline⁵⁸. As shown in Table II-13 and detailed below, SCE tabulates the dollar-per-gallon equivalent fuel costs across different rate options:

⁵⁸ Assumes transport efficiencies of 30 miles per gallon and 3.1 miles per kWh.

- Customers on TOU-EV-8 had an *average load factor of 15 percent*, and based on Option-E rates, an average fuel cost estimate of \$5.48-per-gallon-equivalent - an equivalent fuel cost that is **21 percent higher** than the current gasoline prices of \$4.54 per-/gallon⁵⁹. In comparison, the energy-only structure of TOU-EV-8 provides additional savings on equivalent fuel costs estimated to be \$3.32 per-gallon-equivalent - an equivalent fuel cost that is **27 percent lower** than current gasoline prices.
- Customers on TOU-EV-9 had an *average load factor of 26 percent*, and based on Option-E rates had an average fuel cost estimate of \$3.16-per-gallon-equivalent - an equivalent fuel cost that is **30 percent lower** than current gasoline prices. In comparison, the energy-only structure of TOU-EV-9 provides additional savings on equivalent fuel costs estimated to be \$2.69 per-gallon-equivalent – an equivalent fuel cost that is **41 percent lower** than current gasoline prices.
- These values, and values derived using other rate options, namely TOU-EV rate options and Option-D rates, are also shown in Table II-13 below.

Table II-13
Annual Average Electric Rate Fuelling Cost for DCFC in \$/gallon Equivalent

Current Tariff	TOU-EV	Option D	Option E	TOU-EV-D 100% FRD	Average Monthly Load Factor
TOU-EV-8	\$3.32	\$8.38	\$5.48	\$4.54	15%
TOU-EV-9	\$2.69	\$3.77	\$3.16	\$2.95	26%
All	\$3.09	\$6.66	\$4.62	\$3.95	19%

4. Reporting of Zero-Emissions Vehicle Rate Participation

The Final Decision in Phase 2 of SCE’s 2018 GRC required SCE to file an information only Advice Letter reporting the relative participation levels for zero-emission vehicle loads on Option-E rates schedules and EV specific rates.⁶⁰ The Advice Letter is triggered when *the total zero-emissions*

⁵⁹ *Weekly Retail Gasoline and Diesel Prices*, U.S. Energy Information Administration, https://www.eia.gov/dnav/pet/pet_pri_gnd_dcus_sca_m.htm, accessed March 15, 2024.

⁶⁰ D.18-11-027, OP 8 at p. 74.

1 vehicle load served on medium and large commercial Option-E rate schedules exceed the total customer
2 load on EV specific rates (i.e., TOU-EV-8 and TOU-EV-9). SCE proposes to discontinue this reporting
3 obligation as the threshold has not been reached since EV specific rates were implemented in March of
4 2019. SCE does not anticipate the trigger being reached given the energy-only pricing structure of EV
5 rates that favors these types of loads subscribing to service on EV rate schedules, and the fact that site
6 utilization and load factors for these types of loads may have not yet matured sufficiently for customers
7 to benefit on the Option-E rate. Additionally, as such loads and/or customer accounts are not uniquely
8 identified when subscribed to the Option-E rate, the tracking process is complicated, and time intensive,
9 as zero-emissions vehicle loads cannot be readily discerned from the standard single meter service
10 account configuration. The insights gained from the current end use load extraction methods are not
11 easily verifiable as it would require time intensive and expensive field verification methods to ensure
12 accuracy. For these reasons, SCE is proposing to end this tracking obligation.

13 **5. Schedules RTP – Real Time Pricing**

14 SCE's current RTP rate schedules offer menus of hourly generation prices to bundled
15 service customers, with the delivery service charges being the same as those offered under the default
16 rate Option D. The applicable hourly pricing for a given day is determined one day in advance and is
17 based on the maximum temperature recorded on the prior day at the Los Angeles Civic Center. The
18 hourly RTP rates are designed revenue neutral to recover the generation revenue requirement of each
19 RTP schedule's Otherwise Applicable Tariff (OAT). The underlying hourly price profiles for energy
20 and capacity are based on cost studies described in Exhibit SCE-02. The illustrative RTP rates are
21 shown in Appendix B and are based on the combined marginal costs and rate design proposals presented
22 in this Application.

23 a) CAISO-Based Dynamic Rate Proposal

24 The Final Decision (D.22-10-022) in Phase 2 of SCE's 2021 GRC directed SCE
25 to submit a CAISO-based RTP proposal with the following criteria: (1) CAISO flow-through pricing
26 (Day-ahead/Real time); (2) Generation Capacity rate layer that is hinged to Net Load or, if we see
27 appropriate, a combination of Net Load and Gross Load; and (3) A design test of revenue neutrality.

1 The CPUC's on-going Rulemaking, Track B of the Demand Flexibility OIR
2 (DFOIR),⁶¹ complemented by the requirements of the CEC's Load Management Standards (LMS) ⁶² is
3 expected to further define guiding principles on the structure, and the corresponding requirements
4 around a CAISO informed marginal cost-based dynamic rate. While SCE awaits a final decision in the
5 CPUC's DFOIR, the CEC's Load Management Standards requires that marginal cost based dynamic
6 rates or programs are made available for all consumer groups by January 1, 2027. Due to the work
7 being conducted in the concurrent CPUC and CEC proceedings, SCE requested and received an
8 extension to submit CAISO informed dynamic rate proposal to align with the LMS timeline.⁶³

9 **6. Distributed Energy Resources (DER) Study**

10 By adopting the Medium and Large Power Rate Group Rate Design Settlement Agreement in D.22-
11 08-001, the Commission directed SCE to conduct an attrition year DER-as-a-Class Study. The Study
12 required SCE, in collaboration with settling parties, to explore the potential of creating a separate DER
13 customer class by examining the following items: 1) types of customers or services that should be part
14 of the DER class, 2) customer size thresholds that may apply to the DER class, and 3) the cost-to-serve
15 DER customers. The objectives of the study included:

- 16 1. Evaluate benefits of DER customers as a separate class. This evaluation may also
17 consider if customers with similar load characteristics (i.e., those with load factors or hourly
18 usage profiles, and kW demands similar to DER customers) should also be grouped within
19 the separate class;
- 20 2. Determine which service options (i.e., EV, Option E, RTP, others) should be included in
21 a DER rate class;

⁶¹ R.22-07-005.

⁶² 21-OIR-03.

⁶³ On January 8, 2024, SCE submitted a letter to the CPUC requesting an extension to submit the CAISO based RTP proposal from March 29, 2024, the filing date of this Application, to January 1, 2025 the expected date when SCE expects to submit an application that is also dependent on guidance received through a final CPUC decision in the DFOIR. SCE's request was approved on February 2, 2024.

3. Study overall benefits of revenue allocation and rate design impacts associated with customers under the separate rate class treatment using the 2021 GRC Phase 2 costs and load studies, adjusted to reflect separate DER class(es), as the basis for the study; and
 4. Align the study with applicable Commission's DER Action Plan 2.0 Vision Elements.
- SCE initiated the Study working group in September of 2022 with parties of the Medium and Large Power Rate Group Settlement Agreement and concluded the Study and working group in February of 2024.

SCE presents its findings in Appendix I of this volume and concludes that DER adoption across different rate/consumer groups has yet to mature and given the limited amount of data SCE is not sufficiently confident in the cost-to-serve analysis to recommend the creation of a separate DER specific rate/consumer group at this time. Given the expansive policy and regulatory support over time, behind-the-meter PV remains the most broadly adopted DER type across rate/consumer groups, with relatively nascent adoption rates for storage, mobile, paired, or otherwise. Much like how computing on the edge of the platform-user interface has, and will continue to fundamentally change how a user experiences content, SCE believes that the optimized integration of behind-the-meter storage, has the potential to fundamentally change customer interaction with the grid, and if integrated correctly, materially enhance how customers can harvest the flexibility of such resources to help grid constraints while potentially lowering system costs in the long-run. As the breadth of DER adoption matures in each rate/consumer group, SCE proposes to continue performing this cost-to-serve analysis across the various DER solutions identified in this Study, as well as any prospective solutions that may be commercialized in the future. Accurately assessing the cost disposition of different DER solutions, especially as they continue to mature, better informs how rates and pricing structures can be designed for evolving segments of the DER ecosystem. The results of SCE's study can be found in Appendix I.

1 **D. Legacy Rates**

2 In the 2015 TOU OIR, the Commission established guidelines for assessing the current TOU
3 periods given changing electricity supply and delivery conditions.⁶⁴ In addition, the Commission
4 established guidelines for limited application of legacy TOU periods in retail rates for certain customers.
5 Specifically, the Commission adopted a legacy measure whereby eligible existing behind-the-meter
6 (BTM) solar customers would retain their legacy TOU periods, *but not rate levels*, for a period of **five**
7 (for residential) or **ten** (for non-residential) years from their individual interconnection dates (*i.e.*,
8 original Permission to Operate (PTO) dates). SCE estimates that non-residential legacy rate customers
9 will continue through 2027.

10 The Commission specified in D.17-01-006 that the adopted legacy provision allows customers to
11 maintain the same TOU periods, but that rate proposals, including allocating marginal costs to TOU
12 periods and setting specific rate levels, would be litigated in utility-specific rate proceedings. This
13 allowed for some measure of alignment between rates developed for legacy TOU periods and the rates
14 developed under the current TOU periods.⁶⁵ *Specifically*, (1) the development of legacy TOU pricing
15 should be consistent with the current TOU marginal costs, and (2) updated pricing for legacy TOU
16 periods should continue to maintain pricing signals that align with the incrementality in prices from off-
17 peak legacy periods to peak legacy periods. SCE’s proposal in this Application continues to adhere to
18 this guidance in the design and development of legacy rate structures by first establishing marginal cost-
19 based rates based on the updated class and seasonal revenue allocations proposed herein, and then
20 adjusting the legacy TOU period pricing to reflect the directional differences in pricing between TOU
21 periods.

⁶⁴ R.15-12-012.

⁶⁵ D.17-01-006, p. 64.

SCE will continue to offer two rate structures with the legacy TOU periods in each rate class.

- The General Service rate classes are offered Legacy Option R and Legacy Option B structures.⁶⁶

- The A&P rate classes are offered Legacy Option A and Legacy Option B structures.⁶⁷

Each of these legacy rate structures will be available until the conclusion of the legacy periods adopted in D.17-01-006 and will be updated periodically in subsequent GRC Phase 2 applications until the rate options sunset dates are reached.⁶⁸ The residential legacy rate options are not presented here, as the residential legacy TOU periods sunset in March 2024.

Rate Design For Non-Residential Legacy Rates: The process for setting the non-residential legacy rates is the same for each legacy rate structure outlined above.

- SCE's design begins with updated cost studies discussed in Exhibit SCE-02 and the updated rate group revenue allocations discussed in Exhibit SCE-03. This allows for consistency in cost basis between legacy and non-legacy rates.
- SCE then summarizes the hourly marginal energy costs, hourly generation capacity marginal costs, and hourly distribution peak-capacity marginal costs into the legacy TOU periods.

This results in assigning the appropriate marginal costs to the underlying legacy TOU periods.⁶⁹

⁶⁶ For the TOU-GS-1 class, SCE offers Legacy Option A, B and C rate structures. The Legacy Option A rate contains the "all energy" pricing feature of the current rate and uses the same seasonal allocation and TOU pricing period adjustments described in this section. The Legacy Option B rate is designed consistent with the other legacy Option B rates. The Legacy Option C rate structure is applicable to RES-BCT generating accounts only and is similar to the other legacy Option A structures.

⁶⁷ Legacy Option A is intended for accounts in which the eligible non-standby solar system is located behind the same meter as the load. Legacy Option B is intended for standby accounts and for NEM-A, VNM and RES-BCT benefiting accounts. The old Option A and R structures were designed for accounts where the eligible non-standby solar system is located behind the same meter as the load. For RES-BCT generating accounts with demands greater than 500 kW, SCE offers a Legacy Option A Standby rate structure, which includes a customer charge, supplemental energy charges, backup TRD charges, and a capacity reservation charge (CRC).

⁶⁸ For Residential customers, legacy TOU period rate structure sunsets in 2024 (D.16-01-044 p. 93) and for Non-Residential, TOU period rate structure sunsets in 2027 (D.17-01-006 p. 64).

⁶⁹ Rates are designed based on this distribution of costs and then scaled using the standard EPMC process typically used in rate-setting during GRC Phase 2 proceedings.

- The assignment of distribution marginal costs sets the *same seasonal allocation* as the non-legacy rates, and also establishes the amount of costs deemed for recovery in the legacy TOU periods.⁷⁰
 - For the Legacy Option B structures, design demand distribution marginal costs are recovered in entirety through a non-coincident demand charge (or FRD charge) and are not bifurcated between energy and demand charges.
 - For the Legacy Option A (with the exception of TOU-GS-1) and Legacy Option R structure, the design demand distribution marginal costs are recovered partially through a non-coincident demand charge, with the balance recovered via time-differentiated distribution energy rates.⁷¹
- At this stage, the legacy rates demonstrate *inverted* price differentials between TOU periods.⁷² Pursuant to the direction provided in D.17-01-006, SCE therefore adjusts the legacy rates to ensure that *price differentials* are directionally incremental across the legacy TOU periods.⁷³
 - For the Legacy Option B rate, the generation energy rates are adjusted to provide a **10 percent differential** between the highest- and lowest-priced TOU period in each season.⁷⁴
75 percent of the summer generation TRD revenues are recovered through the on-peak

⁷⁰ The Legacy Option B rates continue to recover generation capacity marginal costs that are allocated to the summer season through summer on- and mid-peak TRD charges. Generation capacity costs allocated to the winter season are recovered through TOU energy charges, and **not** a winter mid-peak TRD charge as designed for the non-legacy rates.

⁷¹ FRD charge for Legacy Option R is set based on the relative ratio of the then current legacy Option R, FRD charge to the current Option E, FRD charge. For TOU-GS-1 design demand distribution marginal costs for Legacy Option A are recovered in entirety through time differentiated cents/kWh energy charges.

⁷² For example, the summer mid-peak price is higher than the summer on-peak price, and the winter off-peak price is higher than the winter mid-peak. This is due to the changing cost profile of electricity, where the highest cost period is shifting to later in the day and the lowest cost period is shifting to the middle of the day.
⁷³ D.17-01-006, fn 48.

⁷⁴ In limiting the applicability of legacy options and requiring the legacy rates to be aligned with updated underlying cost structures, it appears the Commission's intent was to reduce the impact of legacy price differentials on generation oversupply and send more accurate price signals based on the utilities' updated costs. Accordingly, SCE sought a balance between complying with D.17-01-006's guidance and setting a price signal consistent with the updated cost.

1 demand charge and the remaining **25 percent** is recovered through the mid-peak demand
2 charge. For the winter, all TRD revenue is recovered via energy charges.

- 3 ○ Legacy Option A and Legacy Option R rates are then set by moving the recovery of
4 summer generation capacity revenues from TRD charges into TOU energy charges.

5 **E. Budget Billing Plan**

6 SCE currently offers a Budget Billing Plan (BBP) program, formerly called the Level Pay Plan
7 (LPP), for its residential and small commercial service customers. Participating customers pay a flat bill
8 for eleven months with a true-up in the twelfth month to account for any differences between their actual
9 and levelized bill amounts over the year.

10 As part of the 2022 RDW, SCE committed to reviewing its “small business customer programs’
11 eligibility for potential expansion to include some TOU-GS-2 customers.”⁷⁵ SCE explored the
12 feasibility of expanding its BBP to a portion of TOU-GS-2 customers, specifically, single-phase service
13 customers in recognition that these smaller single-phase customers are the most similar in size and bill
14 amounts to the TOU-GS-1 customers who are currently eligible for the program. Therefore, with this
15 customer segment in mind, SCE identified that changes are needed to expand the program to single-
16 phase service TOU-GS-2 customers, such as system enhancements to enroll and to perform calculations
17 specific for TOU-GS-2 customers, required changes to Rules and Tariffs, revenue recovery impacts, and
18 changes to marketing materials.⁷⁶ Most of the Rule and Tariff changes are associated with language to
19 include the newly eligible segment. With respect to the expected revenue shift, approximately 1 percent
20 of the TOU-GS-1 population currently participates in the BBP. A similar proportion of the single-phase
21 service TOU-GS-2 population would equal approximately 100 additional customers in the program.
22 Because the program is designed to help customers manage month-to-month cashflows and trues up
23 annually, the expansion of BBP is not expected to produce a revenue imbalance. Should an imbalance
24 occur due to the misalignment of the annual consolidated rate change and the BBP true up cycle, for
25 example, the shift associated with the expansion would be immeasurable from a rate impact perspective.

⁷⁵ A-22-12-004, p. 2.

⁷⁶ D.00-06-034, p. 104, OP 6.

1 However, participation in the program could be a valuable affordability tool, especially in economically
2 distressed areas. Thus, SCE proposes to expand the BBP program to allow single-phase TOU-GS-2
3 customers to participate, but the extension will initially be limited to approximately 100 customers.
4 SCE plans to provide training to phone center representatives and Account Managers on the availability
5 of this program to TOU-GS-2 single-phase customers. SCE also plans to update sce.com to reflect this
6 information as well. Additionally, SCE will work with interested parties during the proceeding to
7 review ME&O for newly eligible BBP customers, such that the ME&O measures are consistent with
8 those performed for customers that are currently eligible for BBP. SCE will also review the
9 effectiveness of the extension with respect to the value of the aid provided and the impact on SCE
10 operations over the attrition years and will make a recommendation regarding program eligibility for the
11 future.

12 **F. Municipal Surcharges**

13 California Public Utilities Code (PUC) Section 6353 requires the “Energy Transporter” to collect
14 franchise fees for public entities based on the bundled service bills, including energy costs, of all
15 customers regardless of their Electric Service Provider (ESP) or Community Choice Aggregator.
16 SCE proposes to continue the current practice of collecting franchise fees to satisfy this statutory
17 requirement. For DA, CA, and CCA customers, SCE calculates the franchise fee amount as it would for
18 a similarly situated bundled service customer and includes the franchise fee as a separate line item on a
19 customer’s bill.⁷⁷

⁷⁷ This is consistent with the approach adopted by the Commission for PG&E in D.00-06-066.

III.

RESIDENTIAL RATE DESIGN PROPOSALS

A. Introduction And Summary Of Proposals

In this section, SCE describes both its currently effective residential rate schedules and SCE's new proposals in this proceeding. Specifically, SCE proposes to (1) maintain the basic baseline allocation at the statutory maximum of 60 percent in each climate zone, (2) modify the existing TOU-D-4-9PM, TOU-D-5-8PM, and TOU-D-PRIME (PRIME) seasonal rate differentials, (3) implement a new variant of TOU-D-PRIME that offers a Time Related Demand (TRD) charge, (4) continue to offer the Heat Pump Water Heater (HPWH) baseline allowance, (5) and implement a Diversity Benefit Adjustment (DBA) for the DMS-3 rate.

B. Overview Of Current Residential Rate Schedules

1. Default TOU Rates

Historically, the majority of residential customers, both single-family and individually metered multi-family accommodations, have taken service on Schedule D, Domestic Service, a non-TOU tiered rate schedule that serves as the basis for the development of most other non-TOU optional rate schedules in the residential rate group. Pursuant to D.19-07-004, SCE made TOU-D-4-9PM the default or standard rate for residential service and migrated eligible residential customers to one of two TOU rates, which differed slightly in that one has a five-hour on-peak period from 4 p.m. to 9 p.m. while the other has a narrower three-hour on-peak period from 5 p.m. to 8 p.m. The migration of eligible customers on to TOU-D-4-9PM or the TOU-D-5-8PM was completed in June 2022. While Schedule TOU-D-4-9PM is the "standard rate" at time of turn-on, customers are nonetheless engaged in conversations about rates at time of turn-on to determine what rate schedule is best for them. Schedule TOU-D-4-9PM features a baseline credit, two-seasonal rate periods (winter and summer), and a five-hour on-peak period from 4 p.m. to 9 p.m. on summer weekdays – In the winter the mid-peak period remains the same from 4 p.m. to 9 p.m. on both weekdays and weekends. SCE proposes to continue offering TOU-D-4-9PM as the default rate option with TOU-D-5-8PM, PRIME, and the Tiered D rate as revenue neutral alternatives.

2. Optional Non-TOU Rates – Tiered Rate Plans

The following is a full list of optional non-TOU rates available to the residential class:

- 1) **Schedule D, Domestic Service**, two-tiered rate structure. This rate consists of a fixed (customer charge), an energy charge, and applies a balance of minimum bill charge when the total bill is below a \$10 floor. Customers are eligible to receive the California Climate Credit under this rate.
- 2) **Schedule D-SDP, Domestic Summer Discount Plan**, which provides credits during the summer season to residential customers who agree to allow SCE to cycle off their air conditioners' compressors under certain conditions. The overall level of credits for participants was approved in D.17-12-003. An illustration of these credit levels is shown in Appendix B and remains at current levels. In accordance with D.16-06-029, SCE does not propose to litigate or update the incentive levels in this proceeding.⁷⁸
- 3) **Schedule D-CARE, California Alternate Rates for Energy Domestic Service**, which provides discounted rates for single-family or multi-family residences meeting certain household income criteria. As a result of D.15-07-001, Schedule D-CARE was designed to provide an average effective CARE discount in the range of 30 percent to 35 percent relative to bills that CARE customers would have paid if they were served on Schedule D. Specifically, D.15-07-001 requires SCE to maintain an average effective CARE discount of **32.5 percent**.⁷⁹ The discount is presented as a single line-item effective discount on customers' bills. The effective line-item discount is also used for customers taking service on TOU rate schedules. Additionally, as part of Track A in the DFOIR, the Commission is considering changes to the calculation of the CARE discount, pursuant to AB 205. Changes resulting from a final decision in

⁷⁸ D.16-06-029, OP 22, directed SCE to seek funding and incentives for all DR programs through the demand response application process beginning in 2018 and future applications.

⁷⁹ D.15-07-001, pp. 231 and 238.

Track A will be noted should SCE file supplemental testimony in this proceeding or new testimony in another Commission determined proceeding.

- 4) **Schedule D-FERA, Family Electric Rate Assistance**, which also provides discounted rates for single-family or multi-family residences meeting certain household income and sizing criteria. The FERA discount for eligible households is **18 percent**. Like CARE, the discount is presented as a single line-item discount on customers' bills to include customers taking service on TOU rate schedules. Similar to CARE, the FERA discount methodology is also being addressed in Track A of the DFOIR. Changes resulting from a final decision in Track A will be noted in supplemental testimony in this proceeding or new testimony in a Commission determined proceeding.
- 5) **Schedule DE, Domestic Service to Utility Employees**, is a long-standing tariff providing discounted rates for utility employees and retirees living in SCE's service territory.
- 6) **Schedule DM, Multifamily Accommodation – Residential Hotel – Qualifying RV Park**, which provides for domestic service to master-metered multifamily accommodations, residential hotels, and recreational vehicle parks. This schedule was closed to new customers on June 13, 1978.
- 7) **Schedule DMS-1, Domestic Service Multifamily Accommodations, Submetered**, for domestic service to master-metered, multifamily accommodations with separately submetered units. This schedule was closed to new customers on December 7, 1981.
- 8) **Schedule DMS-2, Domestic Service Mobilehome Park Multifamily Accommodation, Submetered**, for domestic service to mobilehome multifamily accommodations with separately submetered units. This schedule was closed to new customers for whom construction commenced after January 1, 1997.

- 1 9) **Schedule DMS-3, Domestic Service, Qualifying RV Park Accommodation,**
2 **Submetered**, for domestic service in a qualified RV park with separately submetered
3 spaces reserved for prepaid month-to-month tenants.
- 4 10) **Schedule MB-E, Medical Baseline Exemption**, which provides an additional
5 baseline allocation or allocation, for eligible customers if: (a) they require regular in-
6 home use of specific medical equipment, such as respiratory equipment for sleep
7 apnea, or (b) the full-time resident of the household is a paraplegic, hemiplegic,
8 quadriplegic, or a multiple sclerosis or scleroderma patient.

9 **3. Optional TOU Rates**

10 SCE also offers a variety of optional TOU rates for residential customers that are designed
11 revenue neutral to the default TOU-D-4-9PM rate and incorporate both the time and non-time variants of
12 marginal cost discussed in SCE-02. Consistent with the default rate, current optional TOU rates are mostly
13 all-volumetric rates.⁸⁰ CARE customers on residential TOU rates are provided the same effective line-item
14 CARE discount as customers served on Schedule D-CARE.⁸¹ Appendix B provides illustrative rates for
15 the following rate schedules:

- 16 1) **TOU-D-5-8PM** is structured similar to the TOU-D-4-9PM default residential rate and
17 only differs by the length of the peak period with its associated pricing. This rate option
18 is also a two-season rate (winter and summer), with a three-hour weekday on-peak

⁸⁰ As discussed in Exhibits SCE-02 and SCE-03, SCE now functionalizes design demand distribution marginal costs by incorporating a two-part allocation: a *grid-related* component that is non-time variant, and a *peak-related* component that is time-variant. For residential customers on TOU rates, the *grid-related* component will continue to be collected via a non-time variant cents-per-kWh distribution energy charge. For the *peak-related* portion, costs are allocated to their respective TOU periods based on the PLRF methodology and will be recovered via time-differentiated distribution energy charges. As such, for residential customers on TOU rates, the total distribution energy rate is comprised of (1) a non-time variant *grid-related* kWh charge and a time-variant *peak-related* kWh charge that varies by TOU period.

⁸¹ The average effective CARE discount is provided through a combination of rate factor exemptions and the application of an effective CARE discount that is recovered as a CARE surcharge from all non-CARE customers. CARE customers are currently exempt from the DWR Bond Charge. Once these exemptions have been removed from the customer's bill, a discount of approximately 29 percent is applied to the balance of charges to achieve an overall average effective CARE discount of 32.5 percent. As of October 1, 2020, the DWR Bond Charge line item is now repurposed for the recovery of the Wildfire Fund Charge. AB1054 introduced exemptions of securitized costs for CARE and FERA customers.

period from 5 p.m. to 8 p.m. and includes the same level of baseline credit as the TOU-D-4-9PM default rate.

- 2) **TOU-D-PRIME** is designed for households with an electric or plug-in hybrid vehicle, residential battery, or building electrification technologies. The rate option is also suitable for households with higher energy usage. A fixed daily basic charge allows for lower Super Off-Peak and Off-Peak rates from 8 a.m. – 4 p.m. and 9 p.m. – 8 a.m., with higher rates during the on-peak period from 4 p.m. - 9 p.m. on weekdays. As of April 2023, Schedule PRIME is the default rate option for customers taking service under the Net Billing Tariff (NBT) option.
- 3) **TOU-D-PRIME Plus** In this Application, SCE proposes a new variation of PRIME as an opt-in rate that offers a higher fixed charge relative to the base PRIME rate as well as a time related demand (TRD) charge. Much like the base PRIME rate, TOU-D-PRIME Plus offers a rate structure that incrementally incentivizes customers who adopt electrification technologies. The addition of the demand equivalent charge enhances the effectiveness of the peak-period price to shape customer behavior to store and shift load away from the peak period. Because most residential customers do not have fifteen-minute demand interval meters, SCE proposes to implement the time-related demand charge based on the customer's maximum hourly demand within the pertinent time-of-use period.

C. Proposal To Adjust Rate Levels Uniformly With Implementation of a Fixed Charge

In Track A of the DFOIR,⁸² the Commission is evaluating proposals to restructure residential rates by increasing the level of the fixed charge. A final decision is expected by July 1, 2024. With the addition of a fixed charge SCE proposes to commensurately reduce distribution-related rate levels on a system average percentage basis and non-bypassable charges, if applicable, on an equal cent-per-kWh basis. SCE

⁸² R.22-7-005.

1 will update its residential rate design proposals in supplemental testimony in this proceeding in light of that
2 final decision to more accurately demonstrate bill impacts.

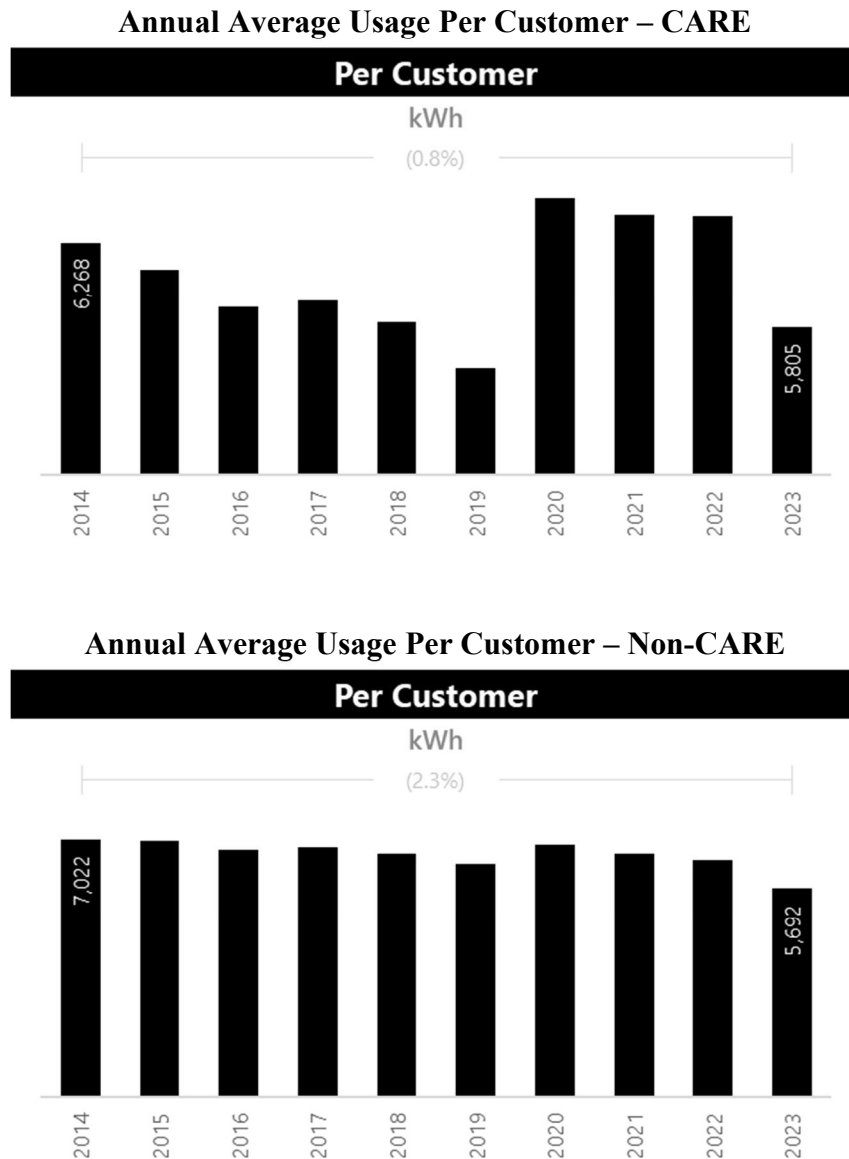
3 SCE's proposed fixed charge would recover costs associated with the customer charge (i.e., meter,
4 final line transformer, and customer service), Energy Efficiency (EE) programs identified in AB 205 in
5 addition to other Public Purpose Programs costs (PPPC), and non-marginal distribution costs (i.e., non-
6 securitized wildfire mitigation costs, distribution capital and O&M, and demand response (DR) programs).

7 **D. Proposal To Maintain The Basic Baseline Allocation At The Statutory Maximum Of**
8 **60 Percent**

9 SCE proposes to maintain the baseline allocation for “basic” customers at the statutory maximum of
10 60 percent. As established in SCE's Preliminary Statement Part H, the “basic” baseline allocation is
11 provided to each residential customer unless the customer qualifies for an “all-electric” baseline allocation.
12 The baseline quantity is billed at a below-average-cost “baseline” (or Tier 1) rate. The proposed baseline
13 allocation for basic customers is consistent with the PUC.⁸³ SCE also proposes to maintain the all-electric
14 baseline allocation, which is currently set at 60 percent for the summer and 70 percent for the winter.
15 Average residential usage levels in SCE's service area have been decreasing over time. As shown in
16 Figure III-8, both CARE and Non-CARE usage has declined, except for during the COVID-19 Pandemic.
17 The effect of this decrease, over time, is that customers receive a smaller allowance of baseline kWh if the
18 baseline percentage is held constant. Keeping the baseline allocation at the statutory maximum provides
19 affordability by maximizing the amount of baseline usage applicable to the lowest tiered rate. For
20 residential TOU rates with a baseline credit, the higher baseline allocation maximizes the value of baseline
21 credit.

⁸³ PUC Section 739 requires that utilities and the Commission designate a baseline quantity of electricity that is necessary to supply “a significant portion of the reasonable energy needs of the average residential customer.” PUC Section 739(a)(1) defines the baseline quantity as a percentage of average residential consumption and specifies that the amount shall range from 50 to 60 percent of average residential consumption (60 to 70 percent for all-electric customers during the winter heating season). SCE's proposal maintains the basic baseline allocation at the maximum of 60 percent as specified in PUC Section 739.

Figure III-8
CARE and Non-CARE Usage Levels Over Time



E. Proposal to Maintain Current Ratio Difference Between Tiered Rates & Resulting Baseline Credit

Recognizing the Commission is expected to authorize a fixed charge for residential rates as part of R.22-07-005, SCE proposes to maintain the current Tiered Rate structure with a Tier 1 and Tier 2 differential of 1.29 to 1. With any level of fixed charge, a reduction in the volumetric rate levels would

1 reduce the cent per kWh difference between Tier 1 and Tier 2 when the ratio method of rate setting is used.
2 Additionally, as revenue requirements increase along with volumetric rates, maintaining a constant ratio
3 between tiers would increase the tier cent-per-kWh differential, thus providing a gradual transition to
4 increased conservation pricing signals.

5 As of January 2024, the 1.29 to 1 current tier rate ratio results in a difference of approximately 10
6 cents per kWh between Tiers 1 and 2. This results in a baseline credit for TOU-D-4-9PM and TOU-D-5-
7 8PM of approximately 10 cents per kWh. SCE proposes to continue to match the difference in tiered rates
8 and the TOU baseline credit to maintain relative parity between the rate options. SCE also proposes to
9 continue adjusting the tier differentials by using a fixed ratio approach instead of the alternative of fixing
10 the cent-per-kWh difference between Tier-1 and Tier-2 at current levels. Maintaining a fixed ratio between
11 tiers 1 and 2 provides greater stability and predictability with tiered rates, even though Tier-1 rates should
12 increase as revenue requirements increase.

13 **F. Proposal To Adjust The Seasonal Differential of TOU Residential Rates**

14 The TOU-D-4-9PM and TOU-D-5-8PM seasonal differentials between summer and winter rates are
15 currently set at 1 cent-per-kWh pursuant to the settlement agreement in SCE's 2017 RDW,⁸⁴ which was
16 adopted in D.19-07-004. PRIME has a seasonal differential of 2.4 cents per kWh. By contrast, the cost-
17 based difference between the seasons is approximately **15 cents-per-kWh**, meaning the average summer
18 rate should be 15 cents-per-kWh higher than the average winter rate. Aligning the seasonal differential
19 with the underlying cost differential provides a more robust price signal that encourages conservation and
20 load shift to avoid peak periods in the Summer. Conversely, lower winter season rates encourage adoption
21 of electrification technologies that contribute to the State's GHG reduction goals. However, making such a
22 drastic change of increasing the seasonal differential from the current 1 cent-per-kwh to approximately 15
23 cents-per-kWh may be too great of an impact on customer bills and materially increase seasonal bill
24 volatility. This would also weigh against the adopted principle of retaining some reasonableness to
25 incremental changes in rates in a manner that generally supports rate and bill stability. SCE therefore

⁸⁴ A.17-12-12.

1 proposes to make a limited move closer to the cost based seasonal difference by increasing the seasonal
2 differential from the current 1 cent-per-kWh to **4 cents-per-kWh** for TOU-D-4-9PM and TOU-D-5-8PM
3 residential rates and increase the seasonal differential for PRIME from the current 2.4 cents-per-kWh to 6
4 cents-per-kWh. This incremental change lowers rates for eight winter months, potentially improving the
5 economics of heat pump adoption, and increases rates for four summer months, potentially encouraging
6 customers to harvest flexible demand in support of grid conditions during those peak summer months. As
7 such, both effects result in positive externalities when viewed through the lens of supporting the
8 Commission's policy objectives around demand flexibility and the State's goals around GHG reduction.
9 This change is in the interest of customers and California's electrification policies as reducing average rate
10 levels for eight winter months can improve the economics of measures that support building electrification.
11 Harvesting any flexibility in residential demand for the summer months more broadly aids in how the
12 residential rate/consumer group can contribute to lowering grid costs by reducing consumption during the
13 more costly peak periods in the summer months. While SCE's TOU-D-4-9PM and TOU-D-5-8PM rates
14 include a seasonal differential of 1 cent-per-kWh, SCE's legacy tier rates do not contain a seasonal
15 differential. SCE therefore proposes to retain the current structure of tiered rates with no seasonal
16 differentials in this Application.

17 As explained below, SCE expects that any volatility introduced by the increased seasonal
18 differential, can potentially mitigated by the adoption of a meaningful fixed charge in Track A of the
19 DFOIR, as a higher fixed charge generally lowers volumetric cent-per-kWh charges. SCE's bill impact
20 analysis that compares customer bill impacts based on the current residential fixed charge of 1 dollar-per-
21 month and proposed 2025 GRC Phase 2 volumetric rate levels result in summer bill *increases* of
22 approximately 4 percent and winter *decreases* of 3 percent as provided in Table III-17.

23 In addition, the bill impacts shown in Table III-14 that compare the existing tiered rate structure to
24 the proposed TOU-D-4-9PM rate structure demonstrate that approximately 65 percent of customers would
25 benefit on the TOU-D-4-9PM rate with the 4 cent-per-kWh seasonal differential. The remaining 35
26 percent of customers, highlighted in grey in the table below, that would not benefit on the TOU rate on an

annual basis, are customers with above average on-peak usage, where the summer bills would otherwise increase above 7 percent.

Table III-14
Bill Impact: Proposed Unchanged Tiered Rate Structure with Proposed TOU-D-4-9

Annual Bill Impact - %	% Customer s	Average				Summer Bills				Winter Bills			
		Monthly kWh	Proposed TOU 4-9	Tiered	Proposed TOU 4-9	Tiered	Impact (%)	Proposed TOU 4-9	Tiered	Impact (%)	Proposed TOU 4-9	Tiered	Impact (%)
A	B	C	D	E	F	G	H=(E-D)/D	I	J	K=(J-I)/I	L	M	N=(M-L)/L
a. <-10%	0%	364	\$ 150	\$ 133	41	37	-11%	\$ 251	\$ 211	-16%	\$ 77	\$ 76	0%
b. -10% - -5%	3%	468	\$ 184	\$ 172	39	37	-6%	\$ 317	\$ 282	-11%	\$ 107	\$ 109	2%
c. -5% - -2%	13%	582	\$ 222	\$ 215	38	37	-3%	\$ 370	\$ 342	-8%	\$ 142	\$ 147	3%
d. -2% - 0%	18%	628	\$ 233	\$ 231	37	37	-1%	\$ 355	\$ 335	-6%	\$ 168	\$ 175	4%
e. 0% - 2%	22%	578	\$ 208	\$ 211	36	36	1%	\$ 283	\$ 272	-4%	\$ 170	\$ 179	5%
f. 2% - 5%	27%	508	\$ 175	\$ 181	35	36	3%	\$ 207	\$ 203	-2%	\$ 160	\$ 170	6%
g. 5% - 10%	14%	445	\$ 149	\$ 158	33	36	6%	\$ 160	\$ 162	1%	\$ 145	\$ 157	8%
h. 10% - 15%	1%	223	\$ 76	\$ 85	34	38	11%	\$ 74	\$ 80	7%	\$ 77	\$ 87	13%
i. 15% - 20%	1%	56	\$ 20	\$ 24	36	42	17%	\$ 18	\$ 20	13%	\$ 21	\$ 25	19%
j. 20% - 25%	0%	39	\$ 14	\$ 17	36	44	22%	\$ 13	\$ 16	19%	\$ 14	\$ 18	23%
k. 25% - 30%	0%	33	\$ 12	\$ 15	35	44	27%	\$ 12	\$ 14	23%	\$ 12	\$ 15	28%
l. >30%	0%	24	\$ 7	\$ 10	30	43	42%	\$ 7	\$ 10	41%	\$ 7	\$ 10	43%
Grand Total	100%	551	\$ 200	\$ 200	36	36	0%	\$ 284	\$ 270	-5%	\$ 157	\$ 165	5%

G. Proposal to Maintain the TOU ratios of TOU-D-4-9PM and TOU-D-5-8PM

In the 2021 GRC Phase 2, the Commission rejected a proposal by SEIA to “increase the summer on-to-off peak differential to the extent necessary to close 15 percent of the difference between the current rates and is fully scaled marginal costs.”⁸⁵ The Commission also directed SCE to “make an affirmative showing of the most accurate and detailed calculations to support just and reasonable rates for TOU D-4-9PM and TOU-D-5-8PM in its next Phase 2 GRC.”⁸⁶

In response to this requirement, SCE considered increasing the peak-period differential to a higher level to give customers the opportunity to further reduce bills by avoiding peak times. Such a change could be justified as most customers have experienced several years on TOU rates and may now be able to better adjust daily usage versus when they were first served on TOU rates. However, since the TOU-D 4-9PM and TOU-D-5-8PM rates are considered default rates, it is preferable to keep these rates “TOU-lite” as determined by D.19-07-004, and provide greater incentive for shifting and savings for the growing number of customers that are enrolling on SCE’s PRIME rate, and eventually its PRIME Plus option.

⁸⁵ D.22-10-022, p. 13.

⁸⁶ D.22-10-022, p. 14.

SCE proposes to maintain the current differentials between the TOU rates at the same levels, in favor of increasing seasonal differentials and driving greater summer conservation. As demonstrated in Table III-15 below, the resulting on-peak rate as a result will increase from 64 cents-per-kWh today, to 66 cents-per-kWh for the 4-9PM rate, already increasing the incentive to curtail energy during on-peak times without any adjustment to the TOU differential. Table III-16 reflects proposed changes for the 5-8PM rate.⁸⁷ However, with the implementation of a fixed charge through the DFOIR, this can be reconsidered given the potential immense rate stabilizing effect of a fixed charge, allowing the TOU differentials to increase to levels that would create strong incentives to conserve during peak periods, while reducing the downside risk of bill volatility for customers that cannot conserve during peak periods.

***Table III-15
Status Quo 4-9pm Rates vs. Proposed Rates⁸⁸***

	Status Quo	Ratio	Proposed	Ratio	% Change
Energy (cents/kWh)- Summer					
On-Peak	63.7	1.6	66.4	1.6	4%
Mid-Peak	51.7	1.3	53.7	1.3	4%
Off-Peak	39.9	1.0	41.3	1.0	3%
Energy (cents/kWh)- Winter					
Mid-Peak	56.3	1.5	54.7	1.5	-3%
Off-Peak	42.7	1.1	41.5	1.1	-3%
S-Off-Peak	38.8	1.0	37.7	1.0	-3%
Summer Avg (cents/kWh)	46.1		47.8		4%
Winter Avg (cents/kWh)	45.1		43.8		-3%
Seasonal Differential	1.0		4.0		

⁸⁷ For the 5to8PM rate option, designing a seasonal differential of 4 cents-per-kw results in increasing the summer on-peak rate from 80 cents-per-kWh to 85 cents per kWh. “Status Quo” and “Proposed” rate design levels assume revenue allocation adjustments as proposed in SCE-03. This allows for a true evaluation of the impact of rate design changes.

⁸⁸ Status Quo refers to rates that use the current rate structures with updated marginal cost revenue allocation.

Table III-16
Status Quo 5-8pm Rates vs. Proposed Rates

	Status Quo	Rato	Proposed	Ratio	% Change
Energy (cents/kWh)- Summer					
On-Peak	79.6	2.0	83.2	2.0	5%
Mid-Peak	59.6	1.5	62.0	1.5	4%
Off-Peak	39.7	1.0	41.0	1.0	3%
Energy (cents/kWh)- Summer					
Mid-Peak	66.0	1.7	63.9	1.7	-3%
Off-Peak	43.4	1.1	42.1	1.1	-3%
S-Off-Peak	37.7	1.0	36.6	1.0	-3%
Summer Avg (cents/kWh)	46.1		47.7		4%
Winter Avg (cents/kWh)	45.1		43.7		-3%
Seasonal Differential	1.0		4.0		

As demonstrated by Table III-17 below, the combined bill impacts as a result of the proposed rate design changes yield reasonable shifts, yielding approximately 4 percent increases in summer and 3 percent decreases in winter. Changes to the 5-8PM rate are similar in that only the seasonal differential is being adjusted.

Table III-17
TOU-D-4-9PM Bill Impacts

Annual Bill Impact - %	% of Customers	Monthly kWh	Current Bill	Average		Annual Summer Bills					Annual Winter Bills		
				Proposed 4-9 Bill	Status Quo	Proposed 4-9	Avg Rate Impact (%)	Status Quo	Proposed 4-9	Avg Rate Impact (%)	Status Quo 4-9 Bill	Proposed 4-9 Bill	Avg Rate Impact (%)
A	B	C	D	E	F	G	H=(E-D)/D	I	J	K=(J-I)/I	L	M	N=(M-L)/L
c. -5% - -2%	16.1%	381	\$135	\$131	35	34	-3%	58	60	4%	141	136	-3%
d. -2% - 0%	35.1%	480	\$172	\$171	36	36	-1%	183	191	4%	167	162	-3%
e. 0% - 2%	45.3%	623	\$226	\$228	36	37	1%	343	358	4%	163	158	-3%
f. 2% - 5%	3.6%	489	\$174	\$178	36	36	3%	255	266	4%	85	82	-3%
Grand Total	100.0%	551	\$199	\$200	36	36	0%	272	284	4%	162	157	-3%

H. TOU-D-PRIME

PRIME was adopted by settlement in SCE's 2018 GRC Phase 2 proceeding as a rate option targeting customers who adopt electrification technologies. D.22-12-056 codified PRIME as the standard

1 rate for customers with distributed generation after April 15, 2023. While PRIME is considered an
2 electrification/DER rate, SCE acknowledges that the PRIME rate is currently conspicuously missing a
3 winter super-off peak period, similar to that of the 4-9PM and 5-8PM rates, from 8 a.m. to 4 p.m. in the
4 winter months – a lower super-off peak rate incentivizes customers to charge behind-the-meter energy
5 storage resources, mobile or otherwise, during this time. While SCE believes such a modest change to
6 PRIME ensures closer alignment with the default rates, SCE recognizes that this rate option was recently
7 adopted as the default rate for customers enrolling on the Net Billing Tariff (NBT), also known as SCE’s
8 “Solar Billing Plan” (SBP). As such, SCE does not propose to create a super off-peak period on the
9 PRIME rate. In order to align PRIME seasonal differentials with the proposed changes to the seasonal
10 differentials in the default TOU-D-4-9PM rate, or the TOU-D-5-8PM rate, SCE proposes to adjust the
11 PRIME seasonal differentials from the current 2.4 cents-per-kWh to of **6 cents-per-kWh**, which will have
12 a smaller impact on customers newly taking service on PRIME while also moving the rate closer to costs.
13 Table III-18 demonstrates the status quo and proposed PRIME Rates:

Table III-18
Status Quo and Proposed PRIME

	Status Quo		Proposed		
	PRIME	Rato	PRIME	Ratio	% Change
Energy (cents/kWh)- Summer					
On-Peak	69.4	2.6	71.7	2.6	3%
Mid-Peak	37.8	1.4	41.4	1.5	9%
Off-Peak	26.4	1.0	27.6	1.0	4%
Energy (cents/kWh)- Summer					
Mid-Peak	63.2	2.6	58.9	2.6	-7%
Off-Peak	23.9	1.0	22.8	1.0	-5%
S-Off-Peak	23.9	1.0	22.8	1.0	-5%
Summer Avg (cents/kWh)	36.7		38.3		4%
Winter Avg (cents/kWh)	34.3		32.3		-6%
Seasonal Differential	2.4		6.0		

Table III-19, below, provides a bill impact analysis of the proposed PRIME compared to the status quo PRIME. The analysis uses PRIME customer profiles from 2023 and does not represent the overall residential population as PRIME customers in general have significantly different usage patterns compared to typical residential customers. For instance, PRIME customers tend to have average monthly usage of over 900 kWh compared to 500 kWh for the average Non-CARE customer. As can be seen below, the impacts are minor with most customers seeing annual impacts of plus or minus 2 percent. Like the TOU rates discussed above, impacts for summer reflect an increase of 4 percent for four months, offset by a decrease of 5 percent during the eight winter months.

Table III-19
Bill Impact Analysis of Status Quo PRIME vs Proposed PRIME

Annual Bill Impact - %	% of Customers	Average		Annual Average Rates (\$/kWh)				Annual Summer Bills			Annual Winter Bills		
		Monthly kWh	PRIME Status Quo	PRIME Proposed	PRIME Status Quo	PRIME Proposed	Average Impact (%)	Status Quo PRIME Bill	Proposed PRIME Bill	Impact (%)	Status Quo PRIME Bill	Proposed PRIME Bill	Impact (%)
A	B	C	D	E	F	G	H=(E-D)/D	I	J	K=(J-I)/I	L	M	N=(M-L)/L
c. -5% - -2%	13%	700	\$231	\$224	33	32	-3%	160	168	5%	\$ 243	\$ 233	-4%
d. -2% - 0%	60%	1008	\$328	\$326	33	32	-1%	360	380	5%	\$ 312	\$ 299	-4%
e. 0% - 2%	25%	935	\$311	\$312	33	33	0%	421	444	5%	\$ 251	\$ 241	-4%
f. 2% - 5%	2%	721	\$250	\$257	35	36	3%	309	326	5%	\$ 170	\$ 164	-4%
g. 5% - 10%	0%	966	\$332	\$350	34	36	5%	334	351	5%	\$ 209	\$ 201	-4%
Grand Total	100%	972	\$318	\$317	33	33	0%	373	393	5%	\$ 291	\$ 279	-4%

I. TOU-D-PRIME Plus

SCE proposes to introduce a version of the PRIME rate that will include a **seasonal TRD charge**, seasonal differential of **8 cents-per-kWh**, and a **higher customer charge of \$33 per month** that includes customer costs and the allocated non-marginal portion of functionalized grid-related cost recovery. Because SCE views PRIME as a DER/ Electrification rate, customers on PRIME are typically expected to have flexible demand resources that can shift load. SCE's analysis has shown that PRIME customers have only 7-8 percent of recorded energy usage during the 4 p.m. to 9 p.m. peak period, compared to 9-12 percent of peak time usage seen with TOU-D-4-9PM and the Tiered rates. This optional variation of PRIME with a TOU-demand charge is being proposed as a more cost-based pilot rate that can demonstrate how similar customers may enhance load flexibility when provided with greater price signals. As the current PRIME rate has recently been determined as the default rate for Solar Billing Plan (SBP) customers, SCE does not intend to migrate PRIME customers to this new variation, nor do we think it is appropriate to simply modify PRIME. For these reasons, we are proposing this variant as an *opt-in* rate for customers who adopt multiple DER and electrification technologies that enable greater levels of load management and shifting while improving comfort and energy burdens.

The rate includes a fixed charge of \$33-per-month, or approximately 1.6 times that of the standard PRIME, and a time related demand charge that is priced on an hourly-per-kW⁸⁹ basis. The time related

⁸⁹ The residential time related demand will be based on an hourly demand rather than the 15-minute interval demand used for non-residential rates. Therefore, the monthly time-related demand will equal to the kWh usage in the weekday on-peak hour with highest usage in each month. For winter, the time related demand will register in the weekday mid-peak hour with the highest usage.

demand charge will be set at \$3.18 per-kW in the summer and \$2.62 per-kW in the Winter. In addition, SCE is introducing a winter super off-peak rate at lower levels to reflect the underlying lower super-off-peak marginal cost to incentivize usage during that time, instead of simply discouraging usage during peak times.

Table III-20, below, provides side by side comparison of rates of the current PRIME compared to the *proposed* PRIME Plus. This comparison is most relevant to demonstrate changes to the rate levels as a result of the changes described above. Notably, all rate levels decrease due to the larger fixed charge, and summer on-peak and winter mid-peak prices decrease due to the on-peak kW charge. Summer peak rates have smaller decreases due to the increased summer revenue appropriately placed in the summer season.

Table III-20
Status Quo PRIME and Proposed PRIME Plus

Energy (cents/kWh) - Summer	Proposed PRIME	Ratio	PRIME Plus	Ratio	% Change
On-Peak	71.7	2.6	65.6	2.6	-9%
Mid-Peak	41.4	1.5	34.4	1.3	-17%
Off-Peak	27.6	1.0	25.7	1.0	-7%
Energy (cents/kWh) - Winter					
Mid-Peak	58.9	2.6	43.2	2.3	-27%
Off-Peak	22.8	1.0	23.3	1.2	2%
S-Off-Peak	22.8	1.0	18.6	1.0	-18%
Demand - \$/kW					
Summer On-Peak	-		3.18		
Winter Mid-Peak	-		2.62		
\$/Month Fixed					
Fixed Charge	20.49		32.62		59%
Seasonal Rates ¢/kWh					
Summer Avg	38.3		36.9		-4%
Winter Avg	32.3		28.9		-11%
Seasonal Differential	6.0		8.0		33%

Table III-21 below, provides a bill impact analysis of the proposed TOU-D-PRIME Plus compared to the proposed TOU-D-PRIME. Similar to the bill impact analysis above examining the proposed changes to PRIME, the analysis also uses PRIME customer profiles from 2023. It does not represent the overall residential population as PRIME customers in general have significantly different usage patterns compared to typical residential customers. While most PRIME customers will see some minor savings, these impacts

do not account for the change in customer behavior the new price signal will encourage. More PRIME customers could make changes and switch to PRIME Plus, demonstrating the power of simple, yet well-defined rate signals, encouraging customers to better align their usage and energy discharge patterns to the needs of the grid. This can provide a powerful demonstration for California to consider in future rate designs.

Table III-21
Bill Impact Analysis of Proposed PRIME vs. PRIME Plus

Annual Bill Impact - %	% of Customers	Average		Annual Average Rates				Summer Monthly Bills			Winter Monthly Bills		
		Monthly kWh	Proposed PRIME	PRIME Demand	Proposed PRIME	PRIME Plus	Rate Impact (%)	Proposed PRIME	PRIME Demand	Impact (%)	Proposed PRIME	PRIME Demand	Rate Impact (%)
a. <-10%	0%	7220	\$2,380	\$2,126	33	30	-11%	3,134	2,970	-5%	\$ 2,134	\$ 1,852	-13%
b. -10% - -5%	15%	1752	\$581	\$542	33	31	-7%	724	704	-3%	\$ 513	\$ 465	-9%
c. -5% - -2%	28%	1049	\$343	\$331	33	32	-4%	433	430	-1%	\$ 298	\$ 282	-6%
d. -2% - 0%	18%	835	\$267	\$264	32	32	-1%	335	337	1%	\$ 234	\$ 228	-2%
e. 0% - 2%	13%	714	\$225	\$227	32	32	1%	278	284	2%	\$ 199	\$ 198	0%
f. 2% - 5%	10%	582	\$183	\$189	32	33	3%	222	232	5%	\$ 163	\$ 167	2%
g. 5% - 10%	6%	401	\$132	\$141	33	35	7%	157	170	8%	\$ 120	\$ 127	6%
h. 10% - 15%	3%	240	\$90	\$101	37	42	12%	103	117	14%	\$ 84	\$ 93	11%
i. 15% - 20%	2%	163	\$68	\$80	42	49	17%	77	91	18%	\$ 64	\$ 74	17%
j. 20% - 25%	1%	121	\$56	\$68	46	56	22%	63	77	23%	\$ 52	\$ 64	22%
k. 25% - 30%	1%	85	\$45	\$58	53	68	27%	51	65	28%	\$ 43	\$ 54	27%
l. >30%	2%	51	\$35	\$52	68	101	48%	39	63	63%	\$ 33	\$ 46	39%
Grand Total	100%	972	\$317	\$307	33	32	-3%	393	392	0%	\$ 279	\$ 266	-5%

J. Heat Pump Water Heater Baseline Allowance

SCE introduced a Heat Pump Water Heater (HPWH) baseline allowance adjustment in its 2021 GRC Phase 2 proceeding. The HPWH adjustment's intent was to encourage the adoption of this new GHG reducing technology in residential customer populations that would not otherwise benefit from taking service on PRIME. These included customers with usage levels lower than the class average monthly usage or those participating in income qualifying programs. The HPWH adjustment provides an incremental baseline allowance to cover the net energy bill increases resulting from switching from a typical natural gas water heater to a typical electric HPWH, for the average customer.

In this Application, SCE proposes to maintain the HPWH adjustments at the same levels adopted in the 2021 GRC Phase 2 proceeding. While the Residential and Small Commercial Rate Design Settlement Agreement, from the 2021 GRC Phase 2 proceeding, calls for SCE to evaluate the appropriateness of the adopted baseline adjustments based on participation data, there was an insufficient level of participation on

the rate modifier, which offer the opportunity to allow SCE to perform a meaningful evaluation of the adjustment levels. Therefore, SCE will continue to use the current adjustment factors and perform an evaluation in its next GRC Phase 2 proceeding if participation levels reach a point where a meaningful evaluation can be performed, as shown in Table III-22 below.

Table III-22
HPWH Incremental Baseline Allowance Amounts (kWh/day)

	Summer kWh per Day	Winter kWh per Day
Basic	1.9	2.6
All Electric	1.9	3

Table III-23 below shows the number of customers in each baseline region known to have HPWHs by December 2022.⁹⁰ Assessing the amount of allowance should consider a full year of data since allowances are seasonally differentiated. Additionally, while baseline allowances are not determined with consideration of various DERs, it is necessary to consider their impact when assessing the incremental load from HPWHs. Regardless of the amount of participation achieved by the next GRC Phase 2, baseline allowances in general, including the HPWH incremental baseline allowance, will be evaluated as a matter of course in the proceeding. Other aspects of the HPWH baseline adjustment (i.e., eligibility requirements, customer verification, and calculation methodology) adopted in the 2021 GRC Phase 2 Residential and Small Commercial Rate Design Settlement Agreement will remain unchanged in this GRC cycle.

⁹⁰ NA signifies combinations of attributes that contain fewer than 15 accounts.

Table III-23
Count of Eligible Accounts with HPWHs

Baseline Region	Non-NEM		NEM		All
	Basic	All Electric	Basic	All Electric	
5		NA			NA
6	56	65	NA	NA	134
8	59	46	NA	NA	114
9	43	33	NA	NA	92
10	39	33	40	20	132
13	NA		NA	NA	NA
14	15	NA	NA	NA	37
15	NA	NA	NA	NA	18
16	NA	NA		NA	16
All	231	204	82	43	560

K. Description Of Master-Metered Schedules And Proposed Net Master Metered Adjustments

SCE currently offers four master-metered schedules that include the same set of charges as Schedule D. Under rate schedules DM, DMS-1, DMS-2, and DMS-3, service is supplied by SCE to more than one residence through a master meter. Additional rate schedule details are shown in Section III.B.2. If residences are sub-metered, tenants are required to be billed by the owner or operator for their usage under Schedule D, Schedule D-CARE, or Schedule D-FERA. The charges in the master-metered rate schedules are adjusted to reflect the specific cost characteristics of master-metered accounts. For example, the Schedules (except for DMS-3) include a submetering discount (*i.e.*, credit) that reduces the distribution rate charged to master-metered customers, which in turn allows them to recover the reasonable cost of providing sub-metered service to their tenants. In D.04-11-033, the Commission approved SCE's methodology for determining the submetering discount based on the marginal costs of service as determined in GRC Phase 2 proceedings.⁹¹ Since this decision was rendered, SCE has based its charges for sub-metered service on marginal costs.

In D.22-08-001, the Commission approved SCE's uncontested Residential and Small Commercial Rate Design Settlement Agreement as part of its 2021 GRC Phase 2 proceeding, which required SCE to "(1) include a proposal to calculate and collect a [Diversity Benefit Adjustment (DBA)]

⁹¹ D.04-11-033, pp. 16-17.

1 from customers served on Schedule DMS-3 and (2) use the single-family underground costs as the starting
2 point for calculating the sub-metering discount⁹².” In this Application, SCE proposes to apply the DBA to
3 DMS-3 using the DBA methodology for DMS-2, which is consistent with treatment for DM and DMS-1
4 customers (see Appendix E for details on how the DBA is calculated). SCE proposes a submetering
5 discount of \$0.283/space/day.

6 The purpose of the diversity adjustment (i.e., charge) is to adjust a master-metered
7 customer’s bill to recognize that a benefit is realized by a master-metered customer who had more sales
8 billed at the lower tiered rates (and less at higher tiered rates) than were used by its sub-metered customers.
9 For example, consider a master-metered customer who has two tenants, each having a baseline allocation
10 of 200 kWh per month, with one park tenant using 250 kWh and the other tenant using 150 kWh per
11 month. The mobile home park as a whole (SCE’s customer) has a baseline allowance of 400 kWh. The
12 park would bill the first tenant for 200 kWh of usage at the baseline rate, and for 50 kWh of usage at a
13 higher rate tier. The park would bill the second tenant for 150 kWh of usage at the baseline rate. However,
14 because SCE would bill the master-metered customer for 400 kWh of aggregate baseline usage at the lower
15 baseline rate, a diversity adjustment is necessary. SCE’s calculation of this adjustment is also contained in
16 Appendix E.

17 Finally, SCE proposes that the basic charge portion of the master-metered bill continue to be
18 calculated using the number of CARE and non-CARE customers in the master-metered park. The net
19 Master Metered Adjustments are shown in Table III-24.

92 See Motion of SCE and Settling Parties for Adoption of Residential and Small Commercial Rate Design Settlement Agreement, Attachment A, p. 22.

Table III-24
Present and Proposed Master Metered Adjustments

Rate Schedule	Category	2021 Proposed Agreement \$/day/space	Proposed Rates \$/day/space
DM	Total Adjustment	0.094	-0.073
DMS-1	Total Adjustment	0.023	-0.167
DMS-2	Total Adjustment	-0.201	-0.474
DMS-3	Total Adjustment	0.024	-0.049

1 IV.

2 **LIGHTING, SMALL AND MEDIUM COMMERCIAL**
3 **AND INDUSTRIAL**

4 **A. Introduction And Summary Of Proposals**

5 In this section, SCE describes both its current Lighting, Small, and Medium Power (LSMP) rate
6 schedules and SCE's new proposals for this segment. In addition to the carryover of most rate design
7 features from the 2021 GRC Phase 2, SCE presents an updated methodology for determining single- and
8 three-phase customer charges for the TOU-GS-1 and TOU-GS-2 classes. Additional proposals
9 applicable to the LSMP segment can be found in Section II.C above.

10 **B. General Service Rate Classes**

11 The LSMP C&I customer group consists of general service customers with demands up to
12 500 kW. LSMP customers are generally provided service within three general service rate classes
13 defined by the customers' monthly non-coincident peak demand:

- 14 • TOU-GS-1 rate class: Monthly demands of 20 kW and less;⁹³
- 15 • TOU-GS-2 rate class: Monthly demands of 21 kW up to 199 kW;⁹⁴ and
- 16 • TOU-GS-3 rate class: Monthly demands of 200 kW up to 500 kW.

17 These general service TOU rate schedules share common pricing features with respect to
18 customer charges, TOU energy rates, and demand charges. In addition to these TOU rate schedules,
19 SCE also offers specialized rate options for LSMP customers who lack interval metering capability,
20 charge EVs on site, have traffic control lighting, wireless infrastructure, or DER technologies, as
21 described below. SCE will continue to provide eligible food banks with a 20 percent line-item discount
22 on their monthly OAT bill.⁹⁵ Additionally, as directed by D.22-08-001, SCE will complete the
23 replacement of meters on Catalina Island to Edison SmartConnect (ESC) meters in 2024. Customers

⁹³ This rate class includes the limited number of customers still served on Schedule GS-1.

⁹⁴ This rate class includes the limited number of customers still served on Schedule GS-2.

⁹⁵ This food bank rate was adopted in D.18-11-027, COL 32.

1 currently taking service on non-time-variant rate options will be transitioned to their applicable TOU-
2 GS-1 and TOU-GS-2 rate schedules by the end of 2024.

3 **1. Schedule TOU-GS-1**

4 The default rate schedule for customers in the TOU-GS-1 rate class is Schedule TOU-
5 GS-1 Option E. For these customers, SCE proposes to establish a revised single-phase monthly
6 customer charge of approximately \$19-per-month, and a three-phase monthly customer charge of \$27-
7 per-month. The seasonal energy charges have been updated to reflect the seasonal generation and
8 distribution capacity marginal costs proposed in this application. SCE uses the default Option E as the
9 base rate when designing revenue neutral optional rates for the class. As discussed in Section II.B.5.a.
10 above, SCE proposes to sunset the default CPP requirement for the TOU-GS-1 rate class.⁹⁶ The legacy
11 TOU rate options will continue to be available, as discussed in Section II.D.

12 In Section II.B.7. above, SCE proposes to continue using a surcharge mechanism to
13 adjust the default single-phase fixed charge for customers receiving the alternative three-phase service.
14 The fixed charge adjustment will be based on the EPMC scaled marginal cost differential between
15 single-phase and three-phase cost of service. SCE is retaining the surcharge mechanism rather than
16 using a unique three-phase service customer charge in recognition that this rate structure is currently in
17 use, is familiar to customers, and represents the lowest cost implementation for this rate component.

18 SCE proposes the following rate treatment for TOU-GS-1 customers:

- 19 • Service on Options D, E or CPP, as described in Section II.B; or on the legacy rate
20 options described in Section II.D.
- 21 • Service on Option LG, which is available exclusively to customers serviced as the
22 Generating Accounts under Schedule RES-BCT.
- 23 • Service on Schedule Option ES, which is available to customers who install onsite
24 behind-the-meter (BTM) energy storage systems, either paired with other technology
25 such as solar or standalone.

⁹⁶ D.18-07-006, pp. 66-68.

- Revise energy, TRD and FRD charges to reflect updated marginal costs and revenue allocations, as described in Exhibits SCE-02 and SCE-03.
- Update the voltage discount and differentiate by season.⁹⁷

2. Schedules TOU-GS-2 and TOU-GS-3

SCE currently offers multiple rate options within the TOU-GS-2 and TOU-GS-3 rate classes. Consistent with D.22-08-001, the default rate schedule in each class is Option D-CPP.⁹⁸ SCE proposes to use Option D as the base rate when designing revenue neutral optional rates for the class. SCE proposes the following rate treatment for TOU-GS-2 and TOU-GS-3 customers:

- Service on Options D, E or CPP, as described in Section II.B; or on the legacy rate options described in Section II.D.
- For TOU-GS-2, establish a three-phase monthly customer charge of approximately \$140-per-month, and a single-phase customer charge of approximately \$34-per-month. Because the typical service phase for TOU-GS-2 is three phase service, SCE will set the default customer charge for the class as three-phase and provide a surcredit for customers taking service on single-phase.
- For TOU-GS-3, establish a customer charge of \$749-per-month. The proposed customer charges for the TOU-GS-2 and TOU-GS-3 rate groups are based on the marginal cost derived in Exhibit SCE-02 and discussed further in Section II.B.1.⁹⁹
- Customer charges for TOU-GS-2 and TOU-GS-3 reflect underlying marginal costs and revenue allocation described in Exhibit SCE-02 and Exhibit SCE-03 respectively and include a rate design adjustment that reallocates up to 50 kVA of transformer cost for recovery through FRD charges.

⁹⁷ See Appendix D.

⁹⁸ *Id.*

⁹⁹ The customer charge is adjusted to recover a portion of the final line transformer costs in the distribution grid demand charge.

- Revise energy, TRD and Non-Coincident peak demand (*i.e.*, FRD) charges to reflect updated marginal costs and revenue allocations, as described in Exhibits SCE-02 and SCE-03.
- Update the voltage discounts.¹⁰⁰

3. Schedule GS-APS-E

Schedule GS-APS-E is an interruptible “Summer Discount Plan” rate for commercial customers. The overall level of credits for participants was approved in D.17-12-003.¹⁰¹ An illustration of the currently available credit levels is shown in Appendix B.¹⁰²

4. Schedules TOU-EV-7

SCE offers Schedule TOU-EV-7, a separately metered commercial rate applicable solely to charging EVs for customers with metered demand up to 20 kW. On September 29, 2023, SCE filed Advice Letter 5113-E to notice the introduction of demand charges in Schedule TOU-EV-7-Option-D¹⁰³, which was approved on January 12, 2024 and subsequently implemented during SCE’s March 1 rate change. Schedule TOU-EV-7-Option-E will remain an energy-only option for separately metered commercial EV charging because the default rate option for the TOU-GS-1 rate/consumer group is an energy-only rate structure, with Option-D available as an opt-in rate for EV customers with higher utilization and energy throughput. Pursuant to D.18-05-040 and Advice Letter 5113-E, the demand charges will be linearly phased in each year at approximately 16.67 percent per year. The demand charges at the end of the 5-year phase-in period will be set to the lower of the percentage of design demand distribution costs related to the grid component adopted in a Phase 2 decision, or 60 percent of

¹⁰⁰ See Appendix D.

¹⁰¹ Pursuant to D.23-12-005, On February 28 2024, SCE submitted Advice Letter 5237-E, requesting CPUC approval to implement incentive rates for Schedules D-SDP, GS-APS-E, TOU-BIP, and AP-I. Because Demand Response incentive rates can change based on Generation Capacity Costs adopted in this Application, SCE will resubmit a Tier 2 AL should any updates to demand response incentive rates stem from costs approved and adopted in this Application.

¹⁰² D.16-06-029, OP 22, directed SCE to seek funding and incentives for all DR programs through the demand response application process beginning in 2018 and future applications.

¹⁰³ AL 5113-E was filed in compliance with OP43 of D. 18-05-040, which requires that demand charges for TOU-EV-7 begin in year six of the transition period, or March 1, 2024.

the design demand distribution marginal costs.¹⁰⁴ Table IV-25 provides an illustration of the phase-in below and reflects updated marginal costs and revenue allocations, as described in Exhibits SCE-02 and SCE-03. SCE retains the energy-only structure of retail transmission rate design but will be phasing in Distribution Demand charges as described in AL 5113-E.

Table IV-25
Illustrative Rates for TOU-EV-7 Option E – Energy-Only Structure; Option D – With Demand Charges

	TOU-EV-7-E	TOU-EV-7-D					
	Energy only Structure	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Customer charge - \$/month	\$18.85	\$18.85	\$18.85	\$18.85	\$18.85	\$18.85	\$18.85
Summer season							
On-peak - \$/kWh	0.62083	0.60130	0.59791	0.59451	0.59112	0.58772	0.58432
Mid-peak \$/kWh	0.30530	0.28577	0.28237	0.27898	0.27558	0.27218	0.26879
Off-peak \$/kWh	0.24046	0.22093	0.21753	0.21414	0.21074	0.20734	0.20395
Winter season							
Mid-peak \$/kWh	0.27658	0.25705	0.25365	0.25026	0.24686	0.24346	0.24007
Off-peak \$/kWh	0.19290	0.17338	0.16998	0.16658	0.16319	0.15979	0.15639
SOff-peak \$/kWh	0.16360	0.14407	0.14068	0.13728	0.13388	0.13049	0.12709
Non-coincident peak demand charge - \$/kW-month							
Transmission	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distribution	0.00	\$0.70	\$1.40	\$2.10	\$2.80	\$3.50	\$4.21
Max kVar charge - \$/kVar-month							

5. Schedule TOU-EV-8

SCE offers Schedule TOU-EV-8, a separately metered commercial rate applicable solely to charging EVs with metered demand greater than 20 kW and up to 500 kW. In this Application, SCE proposes to maintain the current TOU-EV-8 rate design and revise the energy charges to reflect updated marginal costs and revenue allocations, as described in Exhibits SCE-02 and SCE-03. Additionally, as mentioned in Section II.C.3 above, SCE proposes to extend the current version of TOU-EV-8 through the end of 2029 and begin a gradual phase-in of demand charges starting January 1, 2030.

C. TC-1 Rate Group

Schedule TC-1 is applicable to customers with traffic control lighting fixtures, directional signs used in public thoroughfare, 24-hour a day lighting used in such locations as tunnels and underpasses,

¹⁰⁴ A.17-01-022 Joint Exhibit 12, Stipulation Between SCE, ORA, NRDC, EDF, SIEMENS, SIERRA CLUB, and CUE, p. 2

1 and illuminated bus stop shelters located in the dedicated road right-of-way where such service is
2 combined with traffic control service. SCE proposes to establish a monthly customer charge of
3 approximately \$22 and to revise the energy charges to reflect scaled marginal energy costs.

4 The energy charge for Schedule TC-1 is a single non-time-differentiated charge, reflecting the
5 continuous operation characteristics of traffic control lighting and reflecting usage in all TOU periods.
6 SCE calculates the TC-1 energy charge based on the lighting load profile which characterizes the service
7 described above and the distribution and generation marginal costs developed in Exhibit SCE-02.¹⁰⁵
8 SCE will maintain the relationship between fixed and volumetric revenue recovery adopted by the
9 Commission in the 2021 GRC Phase 2 Streetlight Settlement Agreement.¹⁰⁶ The TC-1 customer charges
10 are designed to recover a portion of final line transformer costs associated with distribution grid charges,
11 where approximately 73 percent of allocated revenue is recovered through volumetric charges and 27
12 percent retained through fixed charge recovery. This helps mitigate bill impacts caused by revenue
13 requirement changes.

14 **D. Schedule WTR (Wireless Technology Rate)**

15 Schedule WTR provides single-phase service for wireless technology industries and utility
16 customers deploying Advanced Metering Infrastructure (AMI) that require unmetered electric service to
17 operate wireless communication devices mounted on existing SCE facilities or other facilities approved
18 by SCE. Pursuant to D.99-11-054, SCE developed Schedule WTR, an unmetered rate with a fixed
19 customer charge and a fixed energy charge per device based on an estimated amount of kWh
20 consumption determined by the nameplate wattage on the given wireless device. When the service
21 incorporates a fuse box, customers are also assessed a monthly inspection fee on a per device basis. The
22 current customer charge is assessed on a Customer Account basis where the parent customer of record
23 (i.e., the Customer Account), not the actual service account associated with the meter, is assessed the

¹⁰⁵ As smart meters have been installed on the TC-1 service accounts, interval data from a sample is used to derive an average profile for this rate group, in the same way as for the other rate groups.

¹⁰⁶ D.22-08-001, Streetlight and Traffic Control Rate Group Settlement Agreement.

1 charge. Therefore, a Customer Account with a single device pays the same amount of customer charges
2 as a Customer Account with over 50 devices connected in a localized region.

3 In the 2021 GRC Phase 2 Streetlight and Traffic Control Rate Group Settlement Agreement,
4 parties agreed that SCE should review the WTR billing arrangement to determine if it is more
5 appropriate to assess the monthly customer charge on a per device basis in its next GRC Phase 2
6 application.¹⁰⁷ SCE reviewed the existing WTR practice and determined the current practice of
7 assessing the customer charge as Customer Account level is appropriate. SCE proposes to maintain the
8 customer charge on a per Customer Account basis.

9 SCE explored converting the existing monthly customer charge to a per device charge by
10 combining it with the monthly inspection fee. The monthly inspection fee represents costs that would
11 normally be included in the customer service portion of the standard customer charge. In all rate
12 classes, the customer charge is associated with costs of connecting the customer to grid, metering, and
13 other customer service costs associated with billing and providing service. WTR service, however,
14 differs in two significant ways. The first difference is that customers on WTR receive unmetered
15 service. The devices generally share a service connection with a streetlight, traffic control light, or
16 general service account. Therefore, the full cost of the connection is not attributed to the WTR account.
17 The second is that WTR service includes a fuse box inspection that is unique to this type of service.
18 SCE has separated the inspection cost from the monthly customer charge because not all WTR customer
19 connections incorporate a fuse box and the inspection fee represents a large portion of the overall
20 monthly costs making it more equitable to assess the fee only on customers with fuse boxes. When the
21 cost contained in the current WTR customer charges are combined with the inspection fee costs, the
22 resulting average customer charge is approximately \$15-per-month-per-device. SCE's review revealed
23 that most WTR customers would see a small decrease in their overall bill of 3 percent on average. The
24 accounts with a large number of devices would incur an increase of 1 percent on average. The alternate
25 approach does not result in an increase or decrease in cost recovery. However, from an operational

¹⁰⁷ See Joint Motion of SCE and CALSLA for Adoption of Streetlight and Traffic Control Rate Group Settlement Agreement, Attachment A-15, p. 12.

standpoint, the alternate approach would require changes to the current billing processes, producing additional costs for very little gain in rate efficiency. These findings coupled with continuing to ensure rate stability resulted in SCE's proposal not to change the current approach of assessing the customer charge on a per Customer Account basis.

Additionally, SCE will continue to offer an expanded tier range, 0-25 and 26-50, for low wattage ancillary devices pursuant to the 2021 GRC Phase 2 settlement agreement. These devices will also continue to be exempt from the monthly inspection charge¹⁰⁸.

E. Schedule S (Standby)

Schedule S (standby) is an option offered to customers with demands of 500 kW or less, who own and operate a generating facility in accordance with retail or wholesale tariffs/rules and require electric service from SCE's electrical system. Customers eligible for this option are required to take service on the Option D rate of the underlying applicable tariff (except for Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT) customers, as discussed below). The standby rate structure under Schedule S consists of a \$-per-kW capacity reservation charge, applied to the monthly standby demand. Back-up time related demand charges are not applicable. Moreover, as explained in Section V.A.1, SCE applies the algorithm originally adopted in its 2015 GRC Phase 2 proceeding to determine the Standby Demand and Supplemental Contract Capacity.

An additional underlying rate option is available to standby customers who take service on Schedule RES-BCT.¹⁰⁹ Generating accounts with demands of *500 kW and below* will continue to be eligible for service on an underlying rate option where generation capacity costs are recovered through TOU energy charges. Specifically, RES-BCT customers at 500 kW and below will be eligible to take service on the proposed Option E, while those eligible for legacy TOU periods will be eligible for

¹⁰⁸ See Joint Motion of SCE and CALSLA for Adoption of Streetlight and Traffic Control Rate Group Settlement Agreement, Attachment A-15, p. 12.

¹⁰⁹ RES-BCT is an optional schedule for local governments and campuses who own and operate an eligible Renewable Generating Facility, as defined in the tariff, with a total effective generation capacity of not more than 5 MW. Customers taking service under this optional rate schedule are required to take service on standby because—unlike NEM customers—they are not standby-exempt. *See* Schedule RES-BCT *available at* https://library.sce.com/content/dam/sce-dclib/public/regulatory/tariff/electric/schedules/other-rates/ELECTRIC_SCHEDULES_RES-BCT.pdf.

1 service on the Legacy Option R.¹¹⁰ These accounts can also take service on their Option D rate structure
2 or Legacy Option B (if eligible) if they prefer.

¹¹⁰ RES-BCT generating accounts served on TOU-GS-1 must take service on Options D or Option LG.
TOU legacy customers must take service on Legacy Option B or Legacy Option C.

V.

LARGE POWER

A. Introduction And Summary Of Proposals For Large Power Rate Classes

SCE has approximately 3,340 large power customers who account for about 29 percent of the kWh delivered through SCE's transmission and distribution (T&D) system. The six large power customer classes consist of customers with demands greater than 500 kW, except for certain large agricultural and water pumping customers.¹¹¹ The classes are first distinguished by the following two design parameters: (1) Level of service received: full utility service (supplemental service) or partial utility service (standby service), and (2) Service voltage (secondary, primary and subtransmission). Customers who receive full utility service are currently served on Option E, Option D, or Option D-CPP. Option D-CPP is offered as the default rate.¹¹² Customers who receive standby service are currently served only on an Option D rate structure, with the exception of RES-BCT customers (*i.e.*, the Generating Account) who also have an Option LG structure available to them.¹¹³

For large power customers, SCE proposes to:

- Service customers on Option D, Option E or Option D-CPP, as described in Section II.B; or on the legacy rate options described in Section II.D. The default option for this class is Option D-CPP.
- Establish monthly customer charges at the full marginal cost-based level adjusted to recover a portion of the final-line-transformer costs in the grid distribution demand charge.

¹¹¹ See SCE's Advice Letter 3728-E that modified the Applicability section in its TOU-PA-3 schedules to include an exception provision for customers exceeding 500kW: *Agricultural Power Service Customers with electric energy and service used on the same Premises where the Customer produces agricultural or horticultural products, including poultry and livestock. Such accounts are not required to take service under Schedules TOU-8 or TOU-8-S.*

¹¹² TOU-8, Option E eligibility is limited to customers with qualifying technologies but expanded to also include specifically, behind-the-meter (BTM) paired storage and BTM stand-alone storage. For DER customers, participation and eligibility caps were further refined in the 2018 GRC Phase 2 settlement.

¹¹³ Schedule TOU-8 Standby Option LG adopted in the 2018 GRC Phase 2 decision will continue to be limited to customers taking service on Schedule RES-BCT (*i.e.*, the generating account only). This RES-BCT Option will be closed to new customers (in all rate groups eligible for this option) upon SCE reaching 125 MW of eligible installed capacity, representing SCE's designated share of the 250 MW statewide RES-BCT capacity cap.

- Update TOU energy, TRD and Non-coincident peak demand (*i.e.*, FRD) charges for both supplemental and standby (back-up) service that reflect updated marginal costs and retain settlement provisions from Phase 2 of SCE’s 2021 GRC around generation and distribution rate design discussed in Section II.B.
- Update the voltage discounts.
- Update the power factor adjustment rate.

SCE will continue to provide eligible food banks with a 20 percent line-item discount on their monthly OAT bill.¹¹⁴

1. Schedule TOU-8-S: Time-of-Use General Service - Large - Standby

Schedule TOU-8-S is a time-variant general service rate schedule that is mandatory for standby customers with demands exceeding 500 kW, except for certain large agricultural and water pumping customers. SCE proposes to use Option D as the default rate option, with an optional rate structure, Option LG, available to the generating accounts of customers taking service on Schedule RES-BCT.

Customers taking service on a standby rate schedule receive both supplemental service (*i.e.*, service for load regularly provided by SCE, regardless of the customers’ operational purpose) and back-up service (also known as “reserve capacity,” or “standby demand” because it refers only to the load SCE serves when the customer’s generator experiences a partial or complete outage). The dual service provided under schedule TOU-8-S is reflected in the demand charges, where costs are recovered through supplemental, back-up, and capacity reservation (standby) charges, as discussed below.

- Energy and demand charges for the various voltage levels reflect differences in the cost to serve customers at different delivery points on the transmission and distribution systems, as well as differences in the usage profiles for these large customers. Option D will continue to include demand and energy charge voltage discounts for service on Schedule TOU-8 at the transmission voltage (220 kV) level.

¹¹⁴ Food bank rate was adopted in D.18-11-027, COL. 32.

Fixed monthly charges, energy charges, and demand charges are therefore calculated at three established voltage levels.¹¹⁵

- Generation Energy Charges: The energy charges within Schedule TOU-8-S represent supplemental service charges and are determined contemporaneously with energy charges for non-standby customers.
- Generation Demand Charges: Supplemental and back-up demand charges are set at their full EPMC levels, based on the marginal cost of generation system peak and flexible capacity, described in Section II.B. Time-variant demand charges are applied in both the summer and winter seasons due to the addition of flexible capacity costs and the resulting allocation of marginal costs to ramping periods that occur year-round.¹¹⁶
- Transmission and Distribution Demand Charges: Transmission and distribution charges apply to both supplemental and back-up service. The distribution grid and peak bifurcation, discussed in Section II.B, applies to supplemental load charges; distribution grid costs are recovered through a monthly non-time variant peak demand charge and distribution peak costs are recovered through a combination of energy and time-variant demand charges. A Capacity Reservation Charge (CRC) recovers the cost of T&D capacity reserved in the event of a generator outage. The CRC will continue to be recovered through a dollar-per-month charge applied to customers' standby demand.

SCE proposes to continue using the standby algorithm adopted in the 2015 GRC Phase 2 proceeding to identify and differentiate between supplemental and back-up service.¹¹⁷ SCE also

¹¹⁵ Service is provided at secondary voltage (below 2 kV), primary voltage (2 kV to 50 kV) or sub-transmission voltage (above 50 kV).

¹¹⁶ Summer mid-peak and off-peak generation capacity costs are recovered via energy charges. TRD charges apply on non-holiday weekdays only; not on weekends or holidays.

¹¹⁷ Although SCE uses the term "back-up load" as differentiated from "supplemental load," SCE notes here that small standby customers, served on Schedule S, do not pay "back-up" demand charges; they pay only the CRC. Thus, "back-up" load in the context of Schedule S customers refers to standby demand (which is applied to the CRC).

proposes to continue the confirmation review process, which allows for an examination of the standby algorithm output.

2. Schedule TOU-8: General Service – Large

Schedule TOU-8 is a time-variant general service rate schedule that is mandatory for non-standby customers with demands exceeding 500 kW, except for certain large water pumping customers and agricultural power service customers. SCE currently offers multiple rate options within Schedule TOU-8: Options D, E, D-CPP, and the legacy TOU rates. Consistent with current practice, SCE proposes to use Option D-CPP of TOU-8 as the base rate option used when designing revenue neutral optional rate options in each respective class.

Fixed monthly charges and energy and demand charges are calculated at three established voltage levels.¹¹⁸ Energy and demand charges for the various voltage levels reflect differences in the cost to serve customers at different delivery points on the transmission and distribution systems, as well as differences in the usage profiles for these large customers. In addition, Schedule TOU-8 continues to include demand and energy charge voltage discounts for service at the transmission voltage (220 kV) level.

In February of 2000, SCE added an experimental service option referred to as the Optimal Billing Period (OBP) to Schedule TOU-8.¹¹⁹ The OBP allows customers to align their billing and production cycles twice within a six-month period and can provide savings to customers with seasonal production cycles such as cotton gins. SCE continues to provide this billing option under Schedule TOU-8.

3. Schedule TOU-8-RBU: Time-of-Use General Service – Large – Reliability Back Up Service

Schedule TOU-8-RBU, or reliability back-up service, provides large customers with an additional service connection to be used solely for reliability or “back-up” purposes.¹²⁰ Not to be

¹¹⁸ Service is provided at secondary voltage (below 2 kV), primary voltage (2 kV to 50 kV) or sub-transmission voltage (above 50 kV).

¹¹⁹ Advice 1437-E.

¹²⁰ Originally established in Advice 1543-E.

1 confused with standby service, reliability back-up service under TOU-8-RBU provides a second metered
2 service connection in addition to the customer's main service as a means to increase service reliability,
3 and may be used only if customers' main service is not available. Reliability back-up service under this
4 option does not exempt a customer from rotating outages.

5 TOU-8-RBU rate schedules are updated to reflect the marginal cost-based charges to the
6 basic TOU-8 rate design and include customer charges, TOU demand charges, and TOU energy charges
7 consistent with Schedule TOU-8. However, because Schedule TOU-8-RBU customers finance the
8 installation of the back-up service electrical facilities through an Added Facilities agreement (Rule 2.H),
9 the following adjustments are made: (1) the monthly customer charge is reduced to shift costs associated
10 with 50 kVA of final line transformation to distribution charges as described in Section II.B.1, (2) the
11 non-time variant distribution demand charges are not applicable, and (3) netting of the time variant
12 demand charges is applicable to avoid double charging the customer for metered maximum demand that
13 may have been registered by the customer's main meter and back-up meter during the same TOU period
14 in a single billing cycle.

15 **4. Schedule TOU-BIP: Time-of-Use General Service – Base Interruptible Program**

16 Schedule TOU-BIP is an interruptible rate for large commercial and industrial customers.
17 The overall level of credits (*e.g.* incentives) for participants was approved in D.17-12-003. Appendix B
18 illustrates current TOU-BIP credits, based on avoided capacity valuation approved in D.17-12-003, and
19 updated to align with the underlying base rates (*i.e.*, Option D rate).¹²¹ SCE will subsequently align
20 TOU-BIP credits with the underlying base rates once key attributes (*e.g.*, value of capacity, rate
21 structure, billing determinants) are approved in this application.

¹²¹ Pursuant to D.23-12-005, On February 28 2024, SCE submitted Advice Letter 5237-E on February 28, 2024, requesting CPUC approval to implement incentive rates for Schedules D-SDP, GS-APS-E, TOU-BIP, and AP-I. Because Demand Response incentive rates can change based on Generation Capacity Costs adopted in this Application, SCE will resubmit a Tier 2 Advice Letter should any updates to demand response incentive rates stem from costs approved and adopted in this Application.

1 **5. Schedule TOU-EV-9 – General Service Time-of-Use Electric Vehicle Charging –**
2 **Demand Metered**

3 SCE currently offers Schedule TOU-EV-9, a separately metered rate applicable solely to
4 the charging of EVs where the charging site has a demand greater than 500 kW. In this Application,
5 SCE proposes to maintain the current TOU-EV-9 rate design and revise the energy charges to reflect
6 updated marginal costs and revenue allocations, as described in Exhibits SCE-02 and SCE-03.
7 Additionally, as detailed in Section II.C.3 above, SCE proposes to extend the current version of TOU-
8 EV-9 through the end of 2029 and begin a gradual phase-in of demand charges starting January 1, 2030.

1 VI.

2 **AGRICULTURAL & PUMPING CUSTOMER GROUP**

3 **A. Introduction And Summary Of Proposals for Agricultural and Pumping rate schedules**

4 The energy needs of the agricultural and pumping (A&P) community are diverse due to the wide
5 variety of electrical applications associated with this group of customers. SCE's A&P customers
6 produce numerous types of products including livestock products, citrus, and grains, and many of the
7 customers undertake water pumping-related activities. In addition to pumping water, wind machine
8 operations may be necessary to produce and preserve some agricultural products. In response to these
9 diverse energy uses, legislation was adopted in 1986 requiring alternative service options for agricultural
10 customers in the form of time-variant and demand response (DR) rate options. Specifically, all
11 California electric utilities must offer tariffs to agricultural producers, where economically and
12 technologically feasible, that provide "optional alternative interruptible service" and "optional off-peak
13 demand service." SCE's current and proposed rate schedules within the A&P rate group meet these
14 requirements by providing options for customers to meet their electrical needs while fulfilling legislative
15 requirements.¹²²

16 SCE's A&P customers are served under the following rate classes:

- 17 • PA-1 and PA-2 rate classes: applicable to non-TOU A&P customers served on Catalina
18 Island only;¹²³
- 19 • TOU-PA-2 rate class: monthly demands up to 199 kW; and
- 20 • TOU-PA-3 rate class: monthly demands of 200 kW up to 500 kW, unless exempted from the
21 500 kW threshold in which case demands can exceed 500 kW.

22 SCE proposes the following rate options under the A&P rate schedules:

¹²² Customers must be enrolled on TOU rate schedules to be eligible for DR programs participation.

¹²³ Per D.22-08-001, SCE received approval to close Schedules GS-1, GS-2, PA-1, and PA-2 after SCE replaces meters on Catalina Island with Edison SmartConnect (ESC) meters. SCE plans to complete meter replacements and transition accounts by end of 2024.

- Serve customers on Option D, Option E or Option CPP, as described in Section II.B with Option D as the *default* rate option; or on the legacy rate options described in Section II.D;¹²⁴
- Establish a monthly customer charge of approximately \$33 for TOU-PA-2 service and approximately \$573 for TOU-PA-3 service;¹²⁵
- Revise TOU energy, TRD and FRD charges to reflect updated marginal costs and revenue allocations, as described in Exhibits SCE-02 and SCE-03;
- Differentiate the voltage discounts by season; and
- Update the Power Factor rate for TOU-PA-3.

1. Closing of Schedules PA-1 And PA-2

D.22-08-001 approved SCE's proposal to replace the meters on Catalina Island to Edison SmartConnect (ESC) meters in 2021/2022, and then transition these customers to applicable TOU-PA-2 rate schedules in 2024. SCE anticipates completing meter replacements and transitioning customers to their respective TOU rates by the end of 2024.

2. Schedules TOU-PA-2 And TOU-PA-3

For customers in the TOU-PA-2 class, *default* service will be provided on *Option D*. Option E and Option CPP are also available to customers in this class.

For customers in the TOU-PA-3 class, *default* service will be provided on *Option D -CPP*. Option E and Option D are also available to customers in this class.

3. Schedule AP-I

Schedule AP-I is the agricultural and pumping interruptible demand response rate schedule. This rate schedule is currently applicable to customers with at least 37 kW of measured monthly maximum demand (or 50 horsepower of connected load) who have agreed to have their loads interrupted by SCE based on the terms and conditions stated in the schedule. Bill credits

¹²⁴ In the 2018 GRC, Option D replaced Option B as the default rate and Option E was designed as a replacement to the Option A rate. SOP customers, meeting eligibility requirements, were allowed to continue to receive services on the legacy rates until the implementation of a final decision in SCE's 2021 GRC Phase 2, however have all transitioned to current rate options as of March 2024.

¹²⁵ The customer charges have been adjusted to recover a portion of the final line transformer costs in the grid distribution demand charge.

(e.g. incentives) for Schedule AP-I were approved in D.17-12-003 and authorized amounts are used to set incentive levels for the year 2025 as presented in this application.¹²⁶ Appendix B illustrates the current AP-I bill credits, which align with the base rates approved in D.17-12-003.¹²⁷

4. Report New And Existing Customers Exceeding 500 kW Maximum Demand

To provide a consistent treatment to its Agricultural Power Service customers, SCE, AECA, and the Farm Bureau entered into a settlement agreement that was later adopted by D.18-01-012 to allow all customers who meet the Tariff Rule 1 definition of “Agricultural Power Service” to be eligible for the TOU-PA-3 rate schedule regardless of the customers’ monthly maximum demand.¹²⁸ As part of the settlement, SCE agreed to “track the number of customers and demand for new and existing Agricultural Power Services customers that exceeded the 500 kW monthly maximum demand threshold and provide such information as part of its application in future GRC proceedings.”¹²⁹ The analysis of customers’ usage over the 12 months ending January 2024 found 173 agricultural service accounts had exceeded the 500 kW threshold at least 3 times. The 173 TOU-PA-3 accounts had a total annual consumption of about 625,100 MWh, with annual maximum demand ranging from 512 kW to just over 7,872 kW. The average annual demand for this group of customers was 1,370 kW. Due to the growing demand for this customer set, SCE plans on reviewing its Rule 1 definition and possible revenue allocation impacts to the class with parties during this proceeding.

¹²⁶ A.17-01-018 – SCE Application for Approval of its 2018-2022 Demand Response Programs and D.17-12-003 – Decision Adopting Demand Response Activities and Budgets for 2018 through 2022.

¹²⁷ Pursuant to D.23-12-005, On February 28 2024, SCE submitted Advice Letter 5237-E on February 28, 2024, requesting CPUC approval to implement incentive rates for Schedules D-SDP, GS-APS-E, TOU-BIP, and AP-I. Because Demand Response incentive rates can change based on Generation Capacity Costs adopted in this Application, SCE will resubmit a Tier 2 AL should any updates to demand response incentive rates stem from costs approved and adopted in this Application.

¹²⁸ SCE’s Advice Letter 3728-E implemented the settlement agreement and modified the Applicability section in its TOU-PA-3 rate schedules to include the following exception provision for customers exceeding 500kW: *Agricultural Power Service Customers with electric energy and service used on the same Premises where the Customer produces agricultural or horticultural products, including poultry and livestock. Such accounts are not required to take service under Schedules TOU-8 or TOU-8-S.*

¹²⁹ See A.17-06-030, Settlement Agreement By And Among Southern California Edison Company, Agricultural Energy Consumers Association, and California Farm Bureau Federation Addressing Eligibility For Service On Agricultura & Pumping Rates, filed November 29, 2017, at p. 5.

1 **5. Discontinue Time Management Load Controller Device Management**

2 A Time Management Load Controller (TMLC) is a device that allows customers to
3 automatically interrupt the operation of their customer-owned equipment during the on-peak period.
4 The TMLC is an optional, utility-owned device installed at the customer's request and is funded through
5 a one-time added facilities charge. The purpose of the device is to provide customers with a dependable
6 option to interrupt their operations to avoid higher cost on-peak period. It was originally designed to
7 work in conjunction with TOU-PA-SOP rates, which were available prior to the implementation of the
8 2018 GRC Phase 2 rates. Following implementation, TOU-PA-SOP customers transitioned to legacy
9 TOU-PA rate schedules and continued to utilize TMLC devices.¹³⁰ Then, as part of SCE's 2021 GRC
10 Phase 2 application, SCE proposed to stop offering TMLC devices and to disable active TMLC devices
11 from their corresponding meters. SCE and Agricultural parties agreed to a settlement, which allowed
12 customers to keep their active TMLC devices until the implementation of the final decision for SCE's
13 2025 GRC Phase 2 Application or until the customers' TMLC device fails, whichever occurs first.¹³¹ In
14 this application, SCE proposes to stop offering TMLC devices and disable active TMLC devices from
15 their corresponding meter upon implementation of a final decision in SCE's 2025 GRC Phase 2
16 Application.

¹³⁰ D.18-11-07 Approved the Motion of SCE, AECA, and CFBF for Adoption of Agricultural and Pumping Rate Group Rate Design Settlement Agreement, which eliminated TOU-PA-SOP rates, however, allowed customers to transition to grandfathered rates and keep their separate service connections.

¹³¹ Motion of SCE, AECA, and CFBF for Adoption of Agricultural and Pumping Rate Group Rate Design Settlement Agreement, dated January 11, 2022.

VII.

STREET AND AREA LIGHTING CUSTOMER GROUP

A. Introduction And Summary Of Proposals

The Street and Area Lighting (SL) customer group is comprised of roughly 37,900 municipal and private sector service accounts that receive electric service for street, highway, commercial, private, and other types of outdoor area lighting. They represent approximately 1.0 percent of SCE's annual delivered energy. SCE's rate design for SL rate schedules reflects the differences in the marginal cost of service for each lamp type and size, operating hours, and service voltage level. For un-metered lamp types, the non-allocated revenue requirement is based on an accounting of the net plant-in-service, inclusive of operation and maintenance (O&M) and tax treatments, associated with un-metered streetlight facilities.

SL rate schedules have different structures, terms, and conditions, depending on the ownership of the lighting facilities and whether the service is metered or not. Hours of operation for all lamps are controlled by switching equipment that turns the lights on either from dusk-to-dawn for all-night service or from dusk-to-midnight for midnight service.

SCE currently offers the following six SL rate schedules:

- **LS-1 - SCE Owned Un-Metered Streetlights** – Un-Metered, Street and highway lighting where SCE owns the streetlight facilities. Schedule LS-1 offers different rates for different lamp types and wattages.
- **LS-2 - Customer Owned Un-Metered Streetlights** – Un-Metered, Street and highway lighting where the customer owns the streetlight facilities. Schedule LS-2 offers different rates for multiple and series service streetlighting systems.
- **LS-3 - Customer Owned Metered Streetlights** – Metered, Street and highway lighting where the customer owns the streetlight facilities. Schedule LS-3 offers different rates for multiple and series service streetlighting systems.
- **OL-1 - SCE Owned Non-Metered Outdoor Lighting** - Dusk-to-dawn lighting for parks, schools, playgrounds, and parking lots where SCE owns the lighting facilities. Service is

1 supplied from overhead lines only, and no more than one pole will be installed in order to
2 provide this service.

- 3 • **DWL - Residential Walkway Lighting** – Un-Metered, SCE, and customer-owned lighting
4 facilities for walkways, greenbelts, and similar common areas of condominium, cooperative,
5 or other residential projects where each single-family accommodation is separately metered
6 by SCE. This schedule is now closed and the remaining Schedule DWL-A customers will be
7 transitioned to OL-1 in October 2024.
- 8 • **AL-2 - Area Lighting** - Metered, single-phase service during the dusk-to-dawn operation of
9 outdoor area lighting, for uses such as, but not limited to, parking lots, pedestrian walkways,
10 billboards, building exteriors, security, sports and recreation areas, monuments, decorative
11 areas, and bus shelters.

12 For un-metered schedules, the overall SL monthly charge reflects cents-per-kWh energy charges,
13 in addition to the monthly lamp facilities charges. The monthly kWh usage charges applied to non-
14 metered schedules are based on pre-defined hourly energy consumption for specific lamp types, wattage,
15 and hours of operation - whether the service is for all-night service or for midnight service.

16 For metered schedules, the monthly charge reflects cents-per-kWh energy charges and a dollars-
17 per-meter-per-month customer charge. The cents-per-kWh energy charges for all SL rate schedules
18 reflect non-time-differentiated energy charges, including the current schedules AL-2-F (intended for
19 area lighting in parks or other facilities) and LS-3 (intended for highway and street lighting), which
20 allow for limited daytime usage. For the legacy time-of use AL-2 option, SCE applies general service
21 (TOU-GS-1 option A) cents-per-kWh summer on-peak and winter mid-peak energy charges to summer
22 and winter on-peak loads to reflect costs associated with distribution, transmission, and generation
23 service, in addition to NBCs.

24 SCE proposes the following updates to its SL rate schedules:

- 25 • Establish a revised monthly customer charge of approximately \$8.25 for schedules AL-2-F
26 and LS-3.

- Determine streetlight non-allocated revenue requirement for streetlight assets recorded in FERC Account 373 using the Results of Operations Model in SCE's GRC Phase 1. Non-allocated revenue is based on forecasted rate base and O&M expenses reflected in SCE's GRC Phase 1 and allocated to the various types of streetlight options using the marginal cost revenue responsibility (MCRR) methodology established in D.13-03-031.
- The monthly lamp facilities charges will be set to increase by twenty percent over the current rate level, with the shortfall recovered through distribution energy charges from un-metered streetlight rate schedules. The shortfall is measured by the difference between the non-allocated revenue requirement and the revenues recovered through the monthly facilities charges.
- SL energy charges are based on generation energy marginal costs and the usage characteristics of SL customers.
- Maintain the non-time-variant rate structure for schedules LS-3 and AL-2-F with monthly limits on the allowable amount of on-peak usage.¹³² The legacy time-of-use AL-2 option will continue to be available for eligible solar customers.

B. Streetlight Rates Revenue And Cost Structure

Revenues attributable to SL customers fall into two categories: Allocated and Non-allocated.

Allocated Revenues: Allocated revenues are those costs resulting from the revenue allocation process and represent the portion of total system-related costs assigned to SL customers for use of the delivery and generation systems. SCE develops allocated revenue requirements associated with distribution system infrastructure and generation energy and capacity for SL customers in the same manner as all other rate groups. Thus, revenues allocated to SL customers are based on the SL rate group's proportion of marginal cost revenues and incorporate the rate group's contribution to

¹³² On a rolling 12-month basis, SCE will compare all usage incurred on an account between the hours of 8 a.m. to 4 p.m. during the preceding 12 months to the account's total usage for the preceding 12 months. If the usage during the hours of 8 a.m. to 4 p.m. exceeds 30 percent of the account's total usage incurred, the account will become ineligible prospectively for service under Schedule AL-2-F and will, at SCE's sole discretion, be placed as soon as practicable on an applicable general service schedule (similar treatment is applied for Schedule LS-3), unless the customer affirmatively and timely elects otherwise.

1 distribution- and generation-related costs. Prior to the 2018 GRC Phase 2 proceeding, these
2 contributions were relatively low because of the SL customers' larger proportion of off-peak (*i.e.*,
3 nighttime) usage.¹³³ Due to evolving grid conditions, the SL rate group receives an allocation of
4 distribution peak- and generation capacity-related. Under the current TOU periods, the high-cost period
5 occurs between the hours of 4 p.m. to 9 p.m., which naturally coincides with the operation of street and
6 area lighting systems for majority of the year.

7 *Non-allocated Revenues*: Non-allocated revenues are those costs assigned only to un-metered SL
8 customers for the use of specific SL facilities, such as lamps and streetlight poles, and are derived using
9 the Results of Operations Model in SCE's GRC Phase 1. The costs are based on the forecast FERC
10 Account 373 Rate Base and O&M expenses attributable to streetlights.

11 **C. Street Lighting Facilities Costs**

12 SCE uses a net-plant-in-service methodology to determine the non-allocated facilities revenue
13 requirement.¹³⁴ The parties proposed to set the non-allocated revenues collected through non-energy
14 charges, using streetlight facilities-related capital and O&M embedded costs. Under this methodology,
15 the non-allocated revenue requirement is allocated to various non-metered lamp types, using the MCRR
16 methodology, which is similar to that used to allocate distribution and generation authorized revenue
17 requirements across rate classes.

18 SCE proposes to set the non-allocated revenue requirement at \$105.492 million for 2025, which
19 is derived using the Results of Operations Model in SCE's GRC Phase 1, using the forecasted Rate Base
20 and O&M expenses reflected in SCE's GRC Phase 1. The revenue requirement has been adjusted for
21 payments to be collected from LS-1 customers who will have enrolled in Schedule LS-1 Option E.¹³⁵
22 The charge is calculated using prevailing assumptions and parameters filed in each GRC Phase 2
23 proceeding, and then applied to the number of LED lamps that are forecasted for the test year. The

¹³³ Schedules AL-2-F and LS-3 are the only exceptions to this rule where some peak period usage is registered. Rates for daytime usage are based on the marginal cost of service for daytime loads.

¹³⁴ The settling parties included California City-County Streetlight Association (CAL-SLA), the Coalition for Affordable Street Lights (CASL) and SCE – SCE's 2015 and 2012 GRC Phase 2 Applications.

¹³⁵ LS-1 Option E is designed with a rate adder to cover the cost of converting to LED streetlight fixtures.

product is then removed from the non-allocated streetlight revenue requirement that is forecasted for the test year. SCE estimates LS-1 Option E revenues to be approx. \$8.930 million for 2025. SCE proposes to cap the increase of the monthly facilities charge at twenty percent. A twenty percent cap reduces the impact to distribution energy charges compared to the five percent cap agreed to in SCE's 2021 GRC Phase 2 proceeding. Table VII-26 below illustrates the bill impacts for a 100W High Pressure Sodium Vapor lamp (and the LED equivalent) for a five percent cap and SCE's proposed twenty percent cap scenarios. The bill impacts are comparable for both scenarios as the increase in the facility charges is being offset by a reduction in the volumetric charge. The twenty percent cap also maintains the existing proportion of non-allocated revenues recovered through facilities charges and distribution energy charges as shown in the table below. Because facilities charges are collected only through nonmetered rate schedules, the revenue shortfall is recovered from unmetered rate schedules through distribution energy charges.

Table VII-26
Proposed Streetlight Revenue Cap Bill Comparison

	October 2023 Rates		5% Facilities Increase		Percent Change over October 2023 Rates		Proposed 20% Facilities Increase		Percent Change over	
	HPSV	LED-equiv	HPSV	LED-equiv	HPSV	LED-equiv	HPSV	LED-equiv	HPSV	LED-equiv
Watts	100	37	100	37			100	37		
kWh per month	40.37	12.90	40.37	12.90			40.37	12.90		
Total Energy Rate (\$/kWh)	0.21000	0.21000	0.34188	0.34188	63%	63%	0.30789	0.30789	47%	47%
Total Energy Charge (\$/month)	8.48	2.71	13.80	4.41			12.43	3.97		
Facilities Charge (\$/month)	9.88	9.86	10.37	10.35	5%	5%	11.86	11.83	20%	20%
Energy Efficiency Premium Charge (EEPC) (\$/month)	NA	1.55	NA	1.87		21%	NA	1.87		21%
Total Charge (\$/month)	18.36	14.12	24.17	16.63	32%	18%	24.29	17.67	32%	25%
Revenue Collected through Facilities (\$000)	67,659		70,912		5%		81,043		20%	
Revenue Collected through Energy (\$000)	19,019		34,580		82%		24,450		29%	
Total Revenue Requirement (\$000)	86,679		105,492		22%		105,492		22%	
Percent of Revenue Collected through Facilities	78%		67%				77%			
Percent of Revenue Collected through Energy	22%		33%				23%			

1. Adjustments To Non-Allocated Revenue Requirements

In each of the attrition years between GRC Phase 2 cycles, the non-allocated streetlight revenue requirement is updated to account for any streetlight sales or transfers, as well as a forecast of revenues collected from LS-1 Option E customers for the conversion of HPSV fixtures to equivalent LED replacements. In addition to revenue requirement, the number of lamps, steel poles, and Timed

1 Auxiliary Power Device Adaptor (TAP) devices, which are used to calculate total non-allocated
2 streetlight revenue collected from then current facilities, are updated to reflect the latest forecast.
3 Both updates take place concurrently with the annual rate change that occurs to update revenue
4 requirements authorized by the Energy Resource Recovery Account (ERRA) proceeding. Upon update
5 of the non-allocated revenue requirement, SCE proposes to cap any further increases of the facilities
6 charge at 5 percent during attrition years. Shortfall between the amount of then updated revenue
7 requirement and revenues collected through capped facilities charges will be rolled into the distribution
8 energy rate and recovered through delivery portion of energy charges. The proposed capped increase
9 will provide a stable transition of the facilities charges to the full non-allocated revenue requirement
10 level, while alleviating the amount of shortfall that is recovered through energy charges.

11 **D. Installation Options**

12 SCE's 2012 GRC eliminated provision of the wood-pole allowance and customers applying for
13 service with a non-standard installation would be responsible for *all* capital- and expense-related
14 installation costs associated with the new streetlight facility. For customers applying for service under
15 Schedule LS-1 with a standard installation consisting of a wood pole and an LED fixture, SCE is
16 responsible for all capital and expense costs associated with the initial streetlight installation, as well as
17 ongoing O&M and replacement service.¹³⁶ SCE also offers customers two installation options under
18 Schedule LS-1– *Applicant Install* and *SCE Install*.¹³⁷

19 **E. Rate Option For Lamps Mounted On SCE Distribution Poles**

20 SCE will continue to offer a rate option for lamps mounted on SCE's distribution poles, as
21 compared to those that are mounted on poles that support only streetlights. SCE currently has 191

¹³⁶ A standard installation consists of an overhead multiple service installation where SCE furnishes bracket or mast arm construction and standard luminaire attached to a wood pole. Starting on March 17, 2017, the *new* installation necessarily includes an LED lamp for customers on Schedule LS-1, per Advice Letter 3651-E.

¹³⁷ *Applicant Install*: The applicant provides installation, labor and material by the applicant's qualified contractor or sub-contractor in accordance with SCE's design and engineering specifications. Applicant then conveys ownership of all necessary installed structures and facilities to SCE. SCE will be responsible for ongoing O&M and replacement service.

SCE Install: At applicant request, SCE provide the design, labor and material for the streetlight facility's installation, and is reimbursed by the applicant for all capital and expense costs. SCE retains ownership of the facilities. SCE is responsible for ongoing O&M and replacement service.

1 customers on this rate option. The distribution pole-mounted rate option includes lamp charges based on
2 the net-plant-in-service methodology and allocation of streetlights' non-allocated revenue requirement,
3 using the marginal costs of standard-configuration luminaires. Customers taking service on this rate
4 option are provided a credit of \$5.41/lamp to the standard configuration charge for each distribution
5 pole-mounted configuration. The lamp charge credit is meant to reflect the lower costs associated with
6 distribution pole-mount configurations. The proposed \$5.41/lamp credit is derived consistent with the
7 methodology adopted in the 2018 streetlight settlement agreement.

8 **F. Dimmable Streetlights**

9 A standard streetlight is made up of the following components: pole, mast arm, luminaire, and
10 photo sensor that turns the lamp on and off at dusk and dawn, respectively. In place of the photo sensor,
11 customer-owned dimmable streetlights have network-controlled modules, which allow customers to
12 wirelessly control lighting levels and thus decrease or increase energy usage (kWh). In addition to
13 adjusting lighting levels to correspond to activities on the ground, the module also has the capability to
14 meter usage¹³⁸ and report outages.

15 In SCE's 2021 GRC Phase 2 proceeding, SCE proposed initiating pilot studies to understand the
16 benefits and costs of dimmable streetlights with network-controlled modules that are associated with
17 smart sensors on LS-1 and LS-2 streetlights.¹³⁹ In D. 22-08-001, the Commission approved the
18 Streetlight and Traffic Control Settlement Agreement,¹⁴⁰ in which parties agreed to examine the
19 potential benefits of smart and communicating streetlight photo sensors for both LS-1 and LS-2
20 customers via a two-phase pilot. In this Application, SCE presents the results of its dimmable streetlight
21 pilot in Appendix H. The pilot concluded that smart and communicating street light sensors are a viable
22 and mature technology, however, since there is still significant work needed to integrate the data into

¹³⁸ Although the network-controlled modules can meter usage, they are not integrated with utility's meter data processing and reporting and billing systems.

¹³⁹ See A.20-10-012, Phase 2 of 2021 General Rate Case Rate Design Proposals, pp. 83-84.

¹⁴⁰ See Motion of SCE and CALSLA for Adoption of Streetlight and Traffic Control Rate Group Settlement Agreement, p. 6.

1 various operational or metering systems, SCE will not be pursuing any rate options to support this
2 technology at this time.

3 SCE had also proposed that customer-owned and SCE-owned streetlight customers who
4 participate in the dimmable streetlight pilots could be placed on the midnight service LS-1 and LS-2
5 rates, as adopted in the 2021 GRC decision. However, because no night-time dimming actually took
6 place to reduce usage, the rate was not utilized or applicable. The midnight option was intended to act
7 as a proxy for the reduced consumption expected from a dimmable streetlight system. Dimming tests
8 were only done during day-light hours and on a small number of lights to demonstrate the capability of
9 the system without asking cities to conduct appropriate studies to allow for reduced lighting levels in
10 night street environment. No further pilot activities are anticipated associated with the deployed smart
11 sensors and affiliated equipment, however this technology may be considered as part of the next
12 generation of advanced metering technology.

VIII.

ECONOMIC DEVELOPMENT RATE PROPOSAL

A. Economic Development Rate Program

Since 1996, the California Public Utilities Commission (CPUC or Commission) has approved five Economic Development Rate (EDR) programs for SCE and its customers, which facilitate the important policy goal of retaining, attracting, and expanding load in California that, “but for” the discount—taken alone or in combination with other incentives—would be lost either to out of state competition or as a result of a business closing altogether.¹⁴¹ The Commission’s approval of SCE’s EDR programs fully effectuates California Public Utilities Code Section 740.4, which provides that the Commission shall authorize public utilities to engage in programs to encourage economic development. As a result of the CPUC’s approval of SCE’s EDR programs, since their inception in SCE’s service area, SCE has entered into 120 EDR contracts¹⁴² that have either retained, expanded, or attracted customer loads in California.

Although there is still available capacity in SCE’s current EDR program, the program’s expiration is anticipated prior to the sunset date, which is the implementation date of a new program authorized in a final decision in this proceeding. To allow SCE continuity in its EDR program, SCE proposes renewing the program in this Application and requests that the Commission approve a new five-year cycle of its EDR program. Under the proposed new EDR cycle:

- The participation cap would be set at 200 MW.
- EDR participants would receive a **20 percent discount** off an eligible customer’s otherwise applicable tariff (OAT).

¹⁴¹ The Commission approved SCE’s first EDR program in D. 96-08-025 and approved subsequent programs or vintages of EDRs in D. 05-09-018 (as modified in D. 07-09-016 and D. 07-11-052), D. 10-06-015 (as modified by D. 11-05-029), D. 15-04-006, and D. 18-11-027.

¹⁴² As of February 2024.

- EDR would be offered to non-residential, non-governmental accounts¹⁴³ with demands above 150 kW,¹⁴⁴ and the contract for discounted service would continue to cover a five-year term for the retention, attraction, and expansion load located within SCE's service area.
- The program would allow 20 small business accounts (i.e., with maximum loads <150 kW) to take service under an EDR tariff.
- EDR participants will be required to execute "but for" affidavits attesting to the fact that "but for" the EDR rate discount, either on its own or in combination with a package of offerings, the business would not have been retained or expanded its load within California or would not have located in California.
- EDR participants will supply documentation to show (a) that the business has out-of-state options for a new facility or an expansion facility or has a current operation in California that is at risk of ceasing operations, and (b) out-of-state choices or other operational scenarios.
- EDR participants will need to pass an eligibility review with the California Governor's Office of Business and Economic Development.
- SCE would continue to submit Annual EDR Reports to the Commission.

Appendix J contains the draft EDR-R Agreement, which provides the proposed redlined changes.¹⁴⁵

B. Regulatory Background and Policy

California Public Utilities Code Section 740.4(a) provides that the Commission shall authorize public utilities to engage in programs to encourage economic development, and the Commission has held that "rate reductions to attract or retain business[es] are in accord with th[is] legislative precept."¹⁴⁶

¹⁴³ The business must also be a relocatable type of business, e.g., a retail store is not a relocatable business because it is locally tied to its consumer base.

¹⁴⁴ Under the current EDR program, the minimum kW threshold load that a commercial customer must have is >150 kW. Businesses are permitted to aggregate accounts to meet the threshold so long as the accounts are located at the same physical facility.

¹⁴⁵ Appendix J presents the redlined changes to SCE's EDR-Retention Agreement; however these changes apply uniformly to all other EDR Agreements. Note: Under SCE's EDR-Expansion Agreement, Section 4.3 references "Section 5.2", instead of "Section 5.3", as shown in the EDR-Retention Agreement.

¹⁴⁶ D. 05-09-018, Conclusion of Law No. 1.

1 Although Section 740.4(a) does not require the Commission to authorize a rate discount, the
2 Commission historically approved rate discounts to effectuate the statute.¹⁴⁷ The Commission first
3 authorized SCE's EDR tariffs in D.96-08-025 to provide incentives to large SCE business customers
4 who otherwise would not retain, expand, or locate their load in California. In D.05-09-018 (as modified
5 by D. 07-09-016 and D. 07-11-052), the Commission found that the cost of electricity is one of the
6 major contributors to the cost of doing business in California, and approved SCE's proposal to continue
7 offering EDRs from 2006 through 2009. In D.10-06-015 (as modified by D.11-05-029), the
8 Commission approved a new EDR program as a result of a settlement agreement between SCE, PG&E,
9 The Utility Reform Network (TURN), the Energy Users Forum (EUF), and what is now the Public
10 Advocates Office at the California Public Utilities Commission (Cal Advocates). In D.15-04-006, the
11 Commission approved a settlement agreement between SCE and Cal Advocates that resolved SCE's
12 application for approval of EDRs for 2014 through 2018.

13 Most recently, in Phase 2 of SCE's 2018 GRC Application, A.17-06-030, the Commission's
14 final decision, D.18-11-027, approved SCE's current EDR program, which is based on a settlement
15 agreement between Cal Advocates, TURN, and the Small Business Utility Advocates (SBUA).¹⁴⁸
16 Under the current EDR program, there is a 200 MW participation cap, under which non-residential, non-
17 governmental accounts with demands above 150 kW¹⁴⁹ receive a 12 percent discount off the eligible
18 customer's OAT under a five-year contract term. 20 small business accounts (i.e., with maximum loads
19 <150 kW) were also approved to take service under an EDR tariff.

20 On December 20, 2022, the Commission granted SCE's request under Rule 16.6 to extend the
21 EDR program cycle date, subject to the program cap, to the earlier of the day before rates implementing
22 the next EDR program, if any, are implemented, or the day before SCE's 2025 GRC Phase 2 rates are

¹⁴⁷ D. 21-11-016, p. 127.

¹⁴⁸ The parties' Settlement Agreement eliminated SCE's prior Enhanced EDR Program which provided that if a commercial customer is located in a city or county with an unemployment rate that is 125 percent or more greater than the previous year's statewide average unemployment rate, then that customer could get a 30 percent discount.

¹⁴⁹ Under the current EDR program, the minimum kW threshold load that a commercial customer must have is >150 kW. Small businesses are permitted to aggregate accounts to meet the threshold so long as the accounts are located at the same physical facility.

implemented (whichever comes first). As of March 2024, 100 MW of the 200 MW cap remain available - SCE anticipates that the current program will only expire prior to the implementation of SCE's new proposed five-year cycle.

1. Other Recent EDR Applications

In addition to SCE's current EDR program cycle, the Commission has also approved EDR programs for California's other electric IOUs, SDG&E and PG&E. In D.19-07-003, the Commission adopted a standard EDR for SDG&E, applicable to eligible non-residential, non-governmental customers consisting of a five-year discount of 12 percent off an eligible EDR customer's monthly bill relative to the customer's OAT. In D.21-11-016, the Commission also adopted a standard EDR discount for PG&E of 12 percent for transmission voltage customers, along with a mid-enhanced and enhanced EDR program discount of 18-20 percent for smaller customers (those served at primary and secondary voltages) depending on the unemployment rate of the city or county that the business is located in.¹⁵⁰ Other public utilities or entities also offer or have offered EDR discounts.¹⁵¹

C. EDR Justification

California is one of the most difficult states in which to do business, and EDR rates are useful in providing at-risk customers an incentive to remain in, move to, or expand in California. This, in turn, will provide more jobs for California utility customers and provide a greater base over which to spread utilities' fixed costs of service. There are three primary areas that make it challenging to retain, attract, and expand businesses in California: (1) California's economic climate, (2) unemployment considerations, and (3) impact of electricity costs. EDRs, alone or in combination with other incentives,

¹⁵⁰ D. 21-11-016, pp. 129-133. Primary voltage (i.e., small) customers could receive a discount of 12 percent (Tier 1 – Standard), 18 percent (Tier 2 - Mid-enhanced when the unemployment rate in the customer's city or county was between 130-150 percent of the California statewide average), or 20 percent (Tier 3 – Enhanced when the unemployment rate in the customer's city or county was above 150 percent of California's statewide average).

¹⁵¹ For example, the following entities provide or have provided EDRs: City of Anaheim, City of Azusa, City of Banning, Imperial Irrigation District, City of Lodi, City of Lompoc, Modesto Irrigation District, Moreno Valley, City of Rancho Cucamonga, City of Redding, City of Riverside, City of Shasta Lake, and City of Vernon.

can be useful in mitigating some of these challenges by incentivizing businesses to remain in, move to, or expand in California.

1. California's Economic Climate

While California's economy has improved since 2022, California's business climate continues to be considered as one of the most difficult among all states. The Tax Foundation's 2023 State Business Tax Climate Index,¹⁵² which compares the scores of different states' tax provisions, ranked California 48th overall – 46th in corporate taxes and 47th in sales taxes, as shown in Table VIII-27 below.

Table VIII-27
2023 State Business Tax Climate Index Ranks and Component Tax Ranks

State	Overall Rank	Corporate Tax Rank	Individual Income Tax Rank	Sales Tax Rank	Unemployment Insurance Tax Rank	Property Tax Rank
CA	48	46	49	47	24	19

Further, according to a study conducted by CNBC that looked at top states for business in 2022, California scored 29th out of the 50 states.¹⁵³ In the study, states were scored on 88 metrics in ten categories of competitiveness, including the cost of doing business, workforce, economy, infrastructure, business friendliness, and access to capital, among other measures. Specifically in the category of economy, companies are seeking states with stable finances and solid economies. According to the 2022 Kosmont-Rose Institute Cost of Doing Business Survey, from 1990 to 2019, 44 percent more businesses left California than moved here.¹⁵⁴ The survey also found that cities in California ranked among the highest for costs: 18 of the 21 highest cost cities in the United States are in California. A study titled “Why Company Headquarters Are Leaving California in Unprecedented Numbers” was recently published by the Hoover Institution, finding that these exits are in part due to the business environment

¹⁵² 2023 State Business Tax Climate Index: <https://taxfoundation.org/research/all/state/2023-state-business-tax-climate-index/>

¹⁵³ America's Top States for Business 2022: The full rankings, *available at* <https://www.cnbc.com/2022/07/13/americas-top-states-for-business-2022-the-full-rankings.html>

¹⁵⁴ Kosmont-Rose Institute 2022 Cost of Doing Business Survey, *available at* <https://roseinstitute.org/costofdoingbusiness/>

1 in California ranking near the bottom of all U.S. states in many categories, including taxes, regulations,
2 litigation costs, labor costs, energy and utility costs, and employee cost of living.¹⁵⁵ The Hoover
3 Institution Study found that in selecting a business location tax rates are a key selection consideration,
4 and California's corporate income tax rate of 8.84 percent is one of the highest in the nation and a
5 significant contributor to why businesses are leaving California.¹⁵⁶

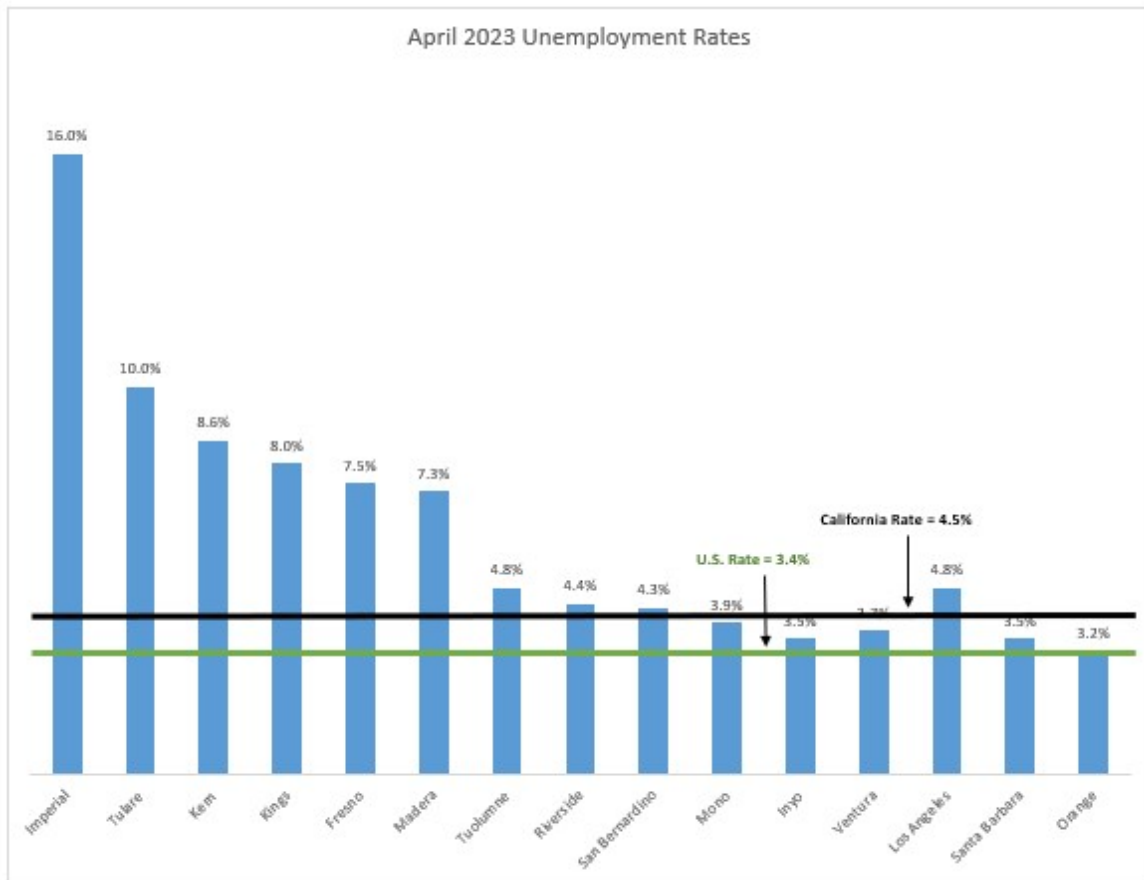
6 **2. Unemployment Considerations**

7 As shown in Figure VIII-9 below, California's statewide average unemployment rate is
8 4.5 percent as of July 2023 and various counties and cities within SCE's service area continue to
9 experience unemployment rates above both the California and national averages. Of the 15 counties
10 located within SCE's service area, eight have unemployment rates that are higher than the statewide
11 average. Similarly, 162 cities within SCE's service area also have unemployment rates that are at least
12 25 percent higher than the statewide average.

¹⁵⁵ California Business Headquarters Now Leaving Twice as Fast, With No End In Sight, *available at*
<https://www.hoover.org/research/california-business-headquarters-now-leaving-twice-fast-no-end-sight>

¹⁵⁶ State Corporate Income Tax Rates and Brackets for 2023, *available at*
<https://taxfoundation.org/data/all/state/state-corporate-income-tax-rates-brackets-2023/>.

Figure VIII-9
Unemployment Rates in Counties Served by SCE Compared to State and U.S. Averages



3. Impact of Electricity Costs

The cost of electricity continues to be a consideration for business retention and attraction in California. As shown below in Table VIII-28, as of November 2, 2023, California's system average rate for electricity was 22.33¢/kWh, the second highest in the nation¹⁵⁷. Additionally, Figure VIII-10 shows that California's average retail price of electricity for all sectors was the highest among 14 states in 2022 and 2023, at 21.09 and 23.32, respectively. California's average retail price of electricity for all

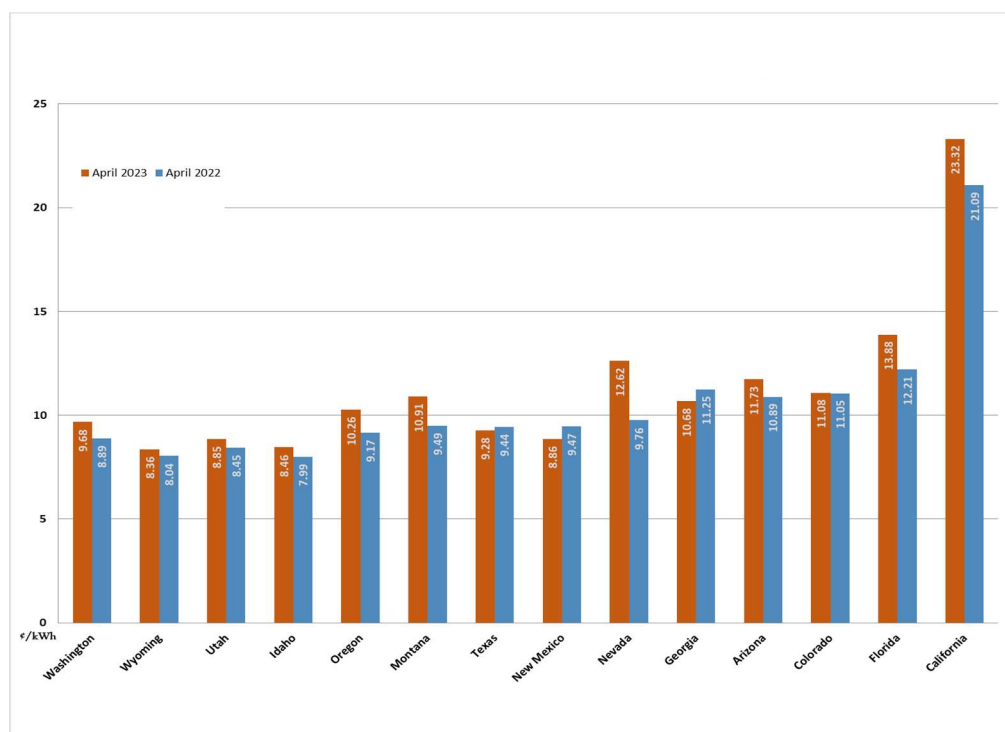
¹⁵⁷ U.S. Energy Information Administration, at US Electricity Profile 2022 - U.S. Energy Information Administration (EIA), www.eia.gov/electricity/state/.

sectors rose by 2.23, or 10.6 percent, from 2022 to 2023, but it was still much higher than the average price of the other states.

Table VIII-28
State Electricity Profiles for 2022

Name	Average retail price (cents/kWh)	Net summer capacity (MW)	Net generation (MWh)	Total retail sales (MWh)
Hawaii	39.72	2,906	9,337,434	9,039,115
California	22.33	85,981	203,383,857	251,869,136
Massachusetts	21.27	12,767	21,026,161	50,983,440
Connecticut	21.08	10,108	43,054,099	27,767,146
New Hampshire	21.07	4,463	18,764,393	10,818,130
Alaska	20.73	2,820	6,694,128	6,002,080
Rhode Island	19.3	2,162	7,819,451	7,576,284
New York	18.33	39,689	125,185,363	143,210,517
Maine	17.44	5,126	12,763,920	11,875,708
Vermont	16.99	839	2,183,829	5,470,471
District of Columbia	14.94	51	160,237	10,241,534
New Jersey	14.8	16,712	65,060,636	74,442,735
Maryland	13.32	11,908	37,139,365	59,682,719
Michigan	13.2	30,538	117,497,052	100,639,262
Florida	12.51	66,883	258,910,413	248,820,803
U.S. Total	12.36	1,161,436	4,230,672,233	3,927,169,069

Figure VIII-10
Average Retail Price of Electric Power – All Sectors – Western States



D. EDR Discount Computation and Ratemaking Treatment

Under the new EDR program, SCE proposes to increase the Standard EDR discount from 12 percent to 20 percent. The contribution to margin (CTM) analysis provides for an increase in the standard EDR to **20** percent, as the increased discount still provides a positive CTM. Even with the 20 percent discount, the expected revenues from EDR participants should account for the sum of distribution and generation marginal costs and non-bypassable charges (NBCs) in each year of the contract's five-year term. SCE proposes to apply the Standard EDR as a flat 20 percent discount on participants' monthly OAT bills. For direct access (DA) and community choice aggregation (CCA) customers' bills, the 20 percent discount is applied to the delivery service components of the monthly OAT bills.

1. Rate Design and Analysis

Table VIII-29 provides SCE's CTM analysis and includes the following inputs: (a) revenues to be collected on a portfolio basis, and (b) marginal cost of serving customers based on the proposed 2023 retail rates.

Table VIII-29
CTM Analysis Across Rate Groups

Contribution to margin (CTM) average rates in ¢/kWh (Bundled service)						
	TOU-GS-1	TOU-GS-2	TOU-GS-3	TOU-8-SEC	TOU-8-PRI	TOU-8-SUB
EDR total bill discount %						
<u>Current 12%</u>						
MC (A)	17.7	16.7	16.4	15.0	14.4	10.5
Retail (B)	23.6	23.5	22.7	21.0	20.3	15.3
CTM (¢/kWh) = B - A	5.9	6.8	6.3	6.0	5.9	4.8
<u>Proposed 20%</u>						
MC (A)	17.7	16.7	16.4	15.0	14.4	10.5
Retail (B)	21.4	21.3	20.6	19.1	18.4	13.9
CTM (¢/kWh) = B - A	3.7	4.6	4.2	4.1	4.0	3.4

The estimated CTM in Table VIII-29 in cents per-kWh is based on the difference between the estimated average OAT retail rate and the estimated average marginal cost rate. The average rate and CTM calculations are based on the average bill for bundled service customers. SCE recognizes that the analysis results in a positive CTM for the targeted rate groups, hence, proposes to set the EDR discount at 20 percent to allow sufficient headroom to address changes in generation revenue requirements that may occur in the attrition years.

2. Ratemaking Treatment of Revenues

Revenues received from bundled service customers will first pay in full all NBCs. The remaining revenues will be recorded to SCE's applicable revenue balancing accounts (e.g., Base Revenue Requirement Balancing Account (BRRBA), Energy Resource Recovery Account Balancing Account (ERRA BA), and Portfolio Allocation Balancing Account (PABA)) in proportion to what the EDR customers' contribution to these accounts would have been absent the discount. Revenues received from DA or CCA service customers are also first used to pay for all NBCs and CRS charges.

To maintain bundled service customers' indifference to the EDR discount, the remaining EDR revenues are allocated to distribution charges only.

E. Administration of the EDR Program

This section addresses the administrative components of the proposed EDR program. These components are substantially similar to those adopted by the Commission in D.18-11-027.

1. Program Size

SCE proposes a cap of 200 MW for the new EDR cycle. SCE believes this amount is still appropriate given the challenging business climate conditions outlined above. As of March 1, 2023, SCE's EDR currently has 100 MW still available. Once SCE's current EDR program is fully subscribed, SCE will not have any additional load available to offer the EDR. Alternatively, if not fully subscribed, SCE's current EDR will terminate and will not be available to customers on the date on which rates implementing SCE's 2025 GRC Phase 2 take effect.

2. Program Commencement

SCE proposes to launch a new cycle of its EDR program on the date the rate schedules implementing SCE's 2025 GRC Phase 2 become effective. SCE proposes that attraction and expansion customers continue to commence service on their respective rates within 24 months of executing an EDR contract, with an additional 12 months granted if infrastructure improvements are required by SCE to serve them. Retention customers shall continue to be eligible to commence service on the rate within twelve months of contract execution, or as soon as at the start of their next regular billing cycle following execution of the EDR contract.

3. Sunset Date

SCE's proposed EDR program will be available to eligible customers until either (1) the day before SCE's 2029 GRC Phase 2 rates are implemented, (2) the day before the effective date of a Commission order terminating the program, or (3) when the EDR cap of 200 MW is met, whichever

comes first.¹⁵⁸ SCE will include the following change to EDR rate schedules, under Special Conditions, to clarify the sunset date for these rate schedules:

“The program will remain open for a customer to execute an EDR Agreement until either (1) the day before SCE’s 2029 GRC Phase 2 rates are implemented, (2) the day before the effective date of a Commission order terminating the program, or (3) the EDR cap of 200 MW is met, whichever comes first.”

SCE will also add:

“This Schedule will remain open until the expiration of all Customer contracts.”

4. Term

SCE proposes to continue the 5-year term for service on the new cycle from the date customers begin receiving service on the rate. At the conclusion of the 5-year term, customers will be billed on their OAT without the EDR discount. Customers are not eligible to renew their EDR contracts once their term expires.

5. Eligibility Criteria

SCE proposes to make the new EDR cycle open to bundled service, DA and CCA commercial (non-residential, non-governmental) customers with loads of 150 kW or more, who are located in SCE’s service area. EDR customers must maintain a minimum load of 150 kW, except for a Small Customer Account, or 75 percent of their base period usage (BPU), as defined in their EDR contract(s), throughout their EDR terms, and are subject to the qualification process described below. For customers aggregating multiple accounts at a single remises to meet the total load demand provisions specified above, the minimum load requirement applies to the aggregation as a whole and not on an individual service account basis.

SCE proposes to make changes to the conservation requirement in the Special Conditions section of the three respective EDR rate schedules to require that customers submit all energy efficiency

¹⁵⁸ On December 20, 2022, the Commission granted EDR Program extension request, which extended the program until the date on which rates implementing SCE’s 2025 GRC Phase 2 take effect, unless the 200 MW program cap is met.

1 efforts implemented or planned for the future as part of the program eligibility review process.

2 Previously, the customer was only required to allow SCE to perform an energy audit to provide energy
3 efficiency and demand side management opportunities.

4 SCE also proposes to clarify in the EDR-R rate schedule that “imminent” means within
5 12 months, when referring to a customer needing to demonstrate “that relocation of its entire operations
6 or a qualified portion of their operations to a site outside of California is a viable alternative or that
7 closure of the Customer’s existing facilities is otherwise imminent.” The new sentence will read as
8 follows:

9 *“The Customer must demonstrate to the satisfaction of SCE that relocation of its*
10 *entire operations or a qualified portion of its operations to a site outside of*
11 *California is a viable alternative or that closure of the Customer’s existing*
12 *facilities within 12 months is otherwise imminent.*

13 Finally, SCE proposes to clarify that accounts belonging to a single customer do not need
14 to be located at the same physical facility, but rather must be located at sites that are both “physically
15 and operationally related.” This change will be to SCE’s EDR agreements, specifically Section 1.13, as
16 shown below:

17 *“1.14¹⁵⁹. Premises: This term shall mean at the ~~same~~ physically and operationally related*
18 *facility(s).”*
19

20 SCE will also submit this and all applicable changes to its EDR tariff changes following a
21 Commission final decision in this proceeding.

22 **6. Qualification Process**

23 SCE continues to utilize the following process to determine if customers meet the EDR
24 eligibility criteria:

- 25 • An SCE economic development consultant contacts customers who have expressed
26 an interest in the EDR program.

¹⁵⁹ EDR-E and EDR-A agreements reference 1.13 for the same content.

- Customers respond by submitting a letter of interest explaining the reason they need the EDR rate discount.
- SCE conducts an EDR rate analysis to determine initial eligibility (e.g., confirmation that monthly load is at least 150 kW, except for a Small Customer Account, and that the customer is not a government entity or a residential customer).
- Customers provide a business justification including total number of jobs and associated benefits/salary as well as a five-year determination of operating costs comparing their selected California location and their potential out-of-state location.
- SCE reviews the information submitted by the customer and approves or denies the customer's request.
- SCE will make an inquiry to document any energy efficiency efforts the customer may have completed or is considering implementing.
- Once approved, SCE enters into an EDR contract with the customer, which documents, among other things, the expected commencement date and expected energy load requirements.

7. Safeguards Against Potential Free Riders

In D.13-10-019, the Commission found that “[f]ree-riders are a risk to any program that provides discounts to qualifying customers.” To address this concern, SCE proposes to continue the following four methods to mitigate the risk of free-riders, who are defined as “customer[s] whose decision to close, locate or expand facilities in [the utility’s] service area is not based upon the proposition that ‘but for’ the lower rates the customer would locate, relocate or expand somewhere outside of [the utility’s] service area, or close.”

a) But for affidavit

SCE proposes to continue to require that all EDR applicants complete an affidavit, under the penalty of perjury, indicating that “but for” the electric rate discount provided by the EDR tariff, either alone or in combination with other incentives, the customer would either move its existing operations outside the state or close altogether.

1 b) Go-Biz Review

2 SCE proposes to maintain the requirement that EDR applicants obtain an
3 independent evaluation of their EDR eligibility from the Office of California Business Investment
4 Services (now known as GO-BIZ) and provide this evaluation to SCE (excluding Small Business EDR
5 applicants).

6 c) Liquidated Damages Provision

7 SCE proposes to continue including a liquidated damages provision in the EDR
8 contracts to ensure that SCE and non-participating customers are not financially or otherwise harmed if
9 the EDR contract is terminated prematurely before the end of its term. In cases of termination for
10 misrepresentation or fraud, SCE proposes to continue to charge liquidated damages for an amount equal
11 to 200 percent of the cumulative difference between the amount the EDR customer would have paid for
12 energy and demand if billed under its OAT, and the amount billed under the EDR. For other causes of
13 early termination, SCE proposes to continue the existing liquidated damages methodology in an amount
14 equal to 100 percent of the cumulative difference described above but update the computation such that
15 the declining discount starts at 33 percent (as opposed to 20 percent) and the annual discount is reduced
16 by 7 percent (as opposed to 4 percent) each year during the contract period. Table VIII-30 below,
17 illustrates the updated computation of the liquidated damages provision.

Table VIII-30
Sample Computation of the Updated Liquidated Damages Provision for EDR Customers

20% EDR Discount - Computation of EDR Liquidated Damages									
Line ID	Descriptor	Year 1	Year 2	Months 25-30	Months 31-36	Year 4	Year 5	Grand Total	Notes
a	OAT	\$400,000	\$400,000	\$200,000	\$200,000	\$400,000	\$400,000	\$2,000,000	
b	EDR Discount - %	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%		
c	EDR Discount	\$80,000	\$80,000	\$40,000	\$40,000	\$80,000	\$80,000		b x a
d	Cumulative EDR Discount	\$80,000	\$160,000	\$200,000	\$240,000	\$320,000	\$400,000		Sum of c
e	EDR Bill	\$320,000	\$320,000	\$160,000	\$160,000	\$320,000	\$320,000	\$1,600,000	a - c
f	Proxy Discount Rate - %	33%	27%	20%	20%	13%	7%		
g	Proxy Declining Discount	\$133,333	\$106,667	\$40,000	\$40,000	\$53,333	\$26,667		f x a
h	Proxy Declining Bill	\$266,667	\$293,333	\$160,000	\$160,000	\$346,667	\$373,333	\$1,600,000	a - g
i	Liquidated Damages (EDR - Proxy)	\$53,333	\$26,667	\$0	\$0	(\$26,667)	(\$53,333)	\$0	e - h
j	Accumulated Damages	\$53,333	\$80,000	\$80,000	\$80,000	\$53,333	\$0		Sum of i

Additionally, SCE proposes to also provide clarification to SCE's EDR Agreement in Section 10, "Liquidated Damages," as it relates to the situation in the current version of Section 9.4, which provides for termination under two scenarios: (1) when a customer is not in compliance with the Agreement or rate schedule, or (2) when a customer ceases operations or relocates outside of SCE's service territory. Currently, if a customer ceases operations while on an EDR rate schedule (i.e., Scenario "2" above), they terminate for non-compliance under Section 9.4 of the Termination section in the EDR Agreement. Section 10.1 provides that any customer who falls under scenarios 1 or 2 of Section 9.4 is terminated for non-compliance and is subject to liquidated damages; however, under Section 10.4, where SCE identifies the termination sections that will be assessed liquidated damages, SCE excludes "business closure or reduction in load without relocation." In order to make it clear to EDR customers that a customer who ceases operations or moves operations outside of SCE's service territory is not liable for paying liquidated damages, SCE proposes that scenario 2 be removed from Section 9.4 and into a new Section 9.8 in Forms 14-981, 14-982, and 14-983 as follows:

SCE proposes that Section 9.4 is modified to:

“9.4 Termination for Noncompliance: SCE may terminate this Agreement upon five business days’ notice if Customer fails to comply with any term or condition of Schedule EDR-R or this Agreement.”

SCE proposes that a new Section 9.8 be added:

“9.8 Termination for Ceasing Operations: SCE may terminate this Agreement upon five business days’ notice if Customer ceases the operations to which this Agreement applies or moves such operations out of SCE’s service territory.”

As seen in Appendix J, SCE proposes that Section 10.4 be modified to:

“For termination under Sections 9.2, 9.3, 9.4, 9.5, or 9.6 above, Liquidated Damages under this Agreement shall be an amount equal to 100 percent of the cumulative difference between (i) the amount billed to Customer under Schedule EDR-R from the date service was first rendered under Schedule EDR-R to the date of termination, and (ii) a "proxy" bill calculation based on a declining discount starting at 20 percent of the Customer’s OAT bill in year one with that annual discount reduced by 4 percent each year thereafter during the same period, *i.e.*, a discount of 16 percent in year 2, 12 percent in year 3, 8 percent in year 4, and 4 percent in year 5, plus interest on that difference (at the Interest Rate) to the date of payment. Should a Customer’s usage increase such that cumulative liquidated damages become negative upon contract termination, under no circumstances will SCE be liable for paying liquidated damages to a Customer.”

With the above changes proposed by SCE, the liquidated damage provision of Sections 10.1 and 10.4 would still apply to Scenario 1 in Section 9.4 when there is noncompliance, but not to situations where the EDR customer ceases operations (which is covered under the new Section 9.8).

d) Participation Limits

SCE proposes to permit EDR retention customers (new, previous or existing) to apply for an EDR discount on existing load for a maximum of one time only. However, retention customers are not barred from applying for an EDR-E or EDR-A for load not covered by the retention agreement.

8. Reporting Requirements

SCE proposes to continue the same reporting requirements adopted by the Commission in D.18-11-027. EDS will continue to encourage customers to report their compliance information no later than January 30 of each year in order to provide timely submissions to the CPUC. Specifically, for the life of the EDR program cycle proposed herein, SCE will file two versions (confidential and non-confidential) of an annual report every March 1 with the director of the Energy Division covering the

1 prior calendar year's EDR activity (and any prorated months depending on when the updated program is
2 implemented). The confidential version of the report will contain the following information for each
3 EDR participant, based on information provided by EDR participants:

- 4 • Name and location;
- 5 • Standard Industry Code applicable to the participant's business;
- 6 • Total EDR discount provided to the EDR participant, and the percent discount given;
- 7 • Annual maximum kW, annual kWh, and the rate schedule of each EDR participant;
- 8 • List of jobs retained or created that are attributable to the EDR participant's
9 involvement in the EDR program; and,
- 10 • Wages and benefits attributable during the reporting period for each job category
11 retained or created by the EDR participant's involvement in the EDR program.

12 The public version of the report will contain an aggregated analysis of the information
13 contained in the confidential report, as follows:

- 14 • Total amount of the annual EDR discounts provided during the reporting period;
- 15 • Total number of jobs created or retained attributable to participation in the EDR
16 program; and,
- 17 • Average salary and benefits attributable to all jobs retained or created by participation
18 in the EDR program.

IX.

VEHICLE TO GRID RESOURCE PROPOSAL

A. Introduction

In this Application, SCE proposes to offer a Vehicle-to-Grid Resource Proposal (VGRP) to provide an export energy credit for vehicle-to-grid (V2G) applications. SCE's proposal as a retail program is a first step at stimulating this segment of the market and is designed to work in concert with the broader vision of SCE's Vehicle-Grid-Integration (VGI) framework, which is described in more detail in Section C.1 of this section below. Historically, V2G has only occurred in pilot programs or lab testing environments. Accordingly, its significant benefits, including broader participation by EV owners or Level 2 charging site hosts in using available mobile-battery capacity in support of the grid and potentially reducing GHG emissions during peak periods by utilizing stored energy in the mobile-battery for discharge on the grid, have not been operationally enabled.

SCE's proposal in this Application and, more broadly, its framework on V2G is generally based on the notion of bidirectional pricing when thinking about the *grid as a service*. Each dimension of the framework acts in concert to support the developing V2G ecosystem. The industry and market continue to identify solutions to engineering limitations that may have existed in the past, and to limit future technical barriers to integrating the V2G capabilities of EV resources. The progress made thus far dovetails with deliberate steps in designing complementary programs that establish appropriate price signals that are critical to the long-term success of an ecosystem that continues to evolve. SCE's proposal therefore acts as a first step in this transition. As the ecosystem for carbon-neutral transportation evolves, and with the proliferation of EVs steadily increasing, it is important to harness the potential of the growing EV fleet in all ways that support the stability and resilience of the electric grid.

The forecasted trajectory of EV adoption in California demonstrates the benefits of this proposal. With the number of on-road EVs in California projected to reach 7.1 million by 2030,¹⁶⁰ driven in large

¹⁶⁰ <https://www.energy.ca.gov/publications/2023/second-assembly-bill-ab-2127-electric-vehicle-charging-infrastructure-assessment>. Staff Report, AB2127, p. 2.

1 part by policies mandating zero-emission vehicles, the state is poised for substantial changes in the
2 automotive industry. Moreover, as the proportion of new zero-emission, light-duty vehicle sales rose
3 from 25 percent in 2023¹⁶¹ to 68 percent by 2030, and reaching 100 percent by 2035,¹⁶² the cumulative
4 battery storage capacity in these vehicles presents an unprecedented opportunity.

5 Despite their considerable energy storage potential, EVs actively engage in transportation
6 services for a fraction of the day and can remain idle for a significant portion of each day. This
7 underutilization of available energy in mobile-battery assets underscores a latent resource that, if tapped
8 effectively, could help address the burgeoning challenges facing the grid as it integrates increasing
9 volumes of renewable energy sources.

10 Within a broader framework of utilizing customer resources to proactively benefit the grid, and
11 recognizing the opportunity to partner with EV customers who can bidirectionally integrate their EVs
12 with the grid, now is the appropriate time to implement this proposal. The export pricing mechanism
13 incentivizes and facilitates the deployment of bidirectional V2G infrastructure and customer
14 participation. By encouraging EV owners to use energy when it's least expensive and share their
15 surplus energy with the grid during high demand, SCE and its customers can create great value through
16 a network of flexible energy resources.

17 To catalyze the adoption of V2G technology and move beyond the realm of pilot projects, it is
18 necessary to establish a clear and equitable compensation framework - a rate option that delineates a
19 transparent and user-friendly pricing schedule, will empower customers to make informed decisions
20 regarding the acquisition of bidirectional charging equipment and integrating their vehicles with the grid
21 in providing energy export retail services. SCE's proposal will be instrumental in taking the right steps
22 to maximize benefits to the grid derived from the energy stored in EVs, thereby limiting the potential
23 risks associated with mass EV adoption.

¹⁶¹ California Energy Commission (2023). New ZEV Sales in California. Data last updated February 1, 2024.
Retrieved March 4, 2024 from <https://www.energy.ca.gov/zevstats>.

¹⁶² California Moves to Accelerate to 100 percent New Zero-Emission Vehicle Sales by 2035:
<https://ww2.arb.ca.gov/news/california-moves-accelerate-100-new-zero-emission-vehicle-sales-2035>.

1 Failure to implement a new *grid as a service* compensation mechanism for V2G not only
2 hampers the realization of the positive externalities inherent in EV proliferation but may also pose
3 additional challenges to proactively engaging customers to contribute toward grid resilience and
4 reliability. By proactively addressing these challenges and embracing the transformative potential of
5 V2G technology, California can navigate the transition towards a sustainable and resilient energy future.

6 **B. Regulatory Background & Procedural History**

7 The CPUC and the CEC continue to play a pivotal role in developing pilots, programs, and
8 services that enable flexible resources like EVs to integrate with the grid while supporting the broader
9 policy objectives of the State, including achieving the State’s clean energy goals and addressing
10 affordability concerns. This section outlines the evolution of regulatory measures and pathways, and the
11 procedural developments in the evolution of pricing for V2G.

12 Two decisions issued in the Commission’s Emergency Reliability Rulemaking,¹⁶³ D.21-03-056
13 and D.21-12-015, established the Emergency Load Reduction Program (ELRP) pilot to generally
14 support grid reliability measures, and included VGI as a subgroup eligible for the ELRP compensation
15 mechanism when EVs with bidirectional capability export excess energy to the grid.¹⁶⁴ While ELRP
16 was intended as an event-based DR program, the CPUC took the first step of establishing a retail
17 compensation mechanism and included mobile-battery discharge during times/events deemed most
18 critical for the grid. ELRP has the limitation of not providing a cost-based long-term solution to act as
19 an effective means of rate design to broadly unlock the value of customer batteries; it only targets a few
20 hours of the year and is only authorized through 2027.

21 In the Emergency Reliability OIR,¹⁶⁵ the CPUC authorized the first phase of SCE’s Dynamic
22 Rate Pilot in D.21-12-015. The pilot looked to proof-of-concept test a bidirectional and symmetric retail
23 pricing framework that utilized CAISO day-ahead pricing signals while also retaining underlying cost-
24 based determinations to design a unified hourly price. The pilot subsequently aligned with the CPUC’s

¹⁶³ R.20-11-003.

¹⁶⁴ E.g., D. 21-12-015, pp. 34-41.

¹⁶⁵ R.20-11-003

1 CALFUSE framework that informs the development of a retail rate structure that can harvest flexible
2 resources, including consideration of how such structures can compensate EV customers for their
3 intermittent charging or discharging to the grid.¹⁶⁶ This is the second example of the CPUC authorizing
4 EV V2G exports and utilizing multiple rate structures to address various use cases and customer
5 segments. The pilot was authorized for three years (2022-2024) beginning no later than May 1, 2022,
6 and was open to bundled residential, commercial and industrial customers.¹⁶⁷

7 In Track B of the DFOIR, R.22-07-005, the CPUC further expanded eligibility and extended
8 SCE's Dynamic Rate Pilot to provide system reliability benefits between June 1, 2024 and December
9 31, 2027.¹⁶⁸ The Commission also adopted an enrollment target of 50 MW of shiftable load and a
10 minimum enrollment level of 10 MW of shiftable load for SCE's Expanded Pilot.¹⁶⁹ SCE submitted a
11 Tier 2 advice letter on March 25, 2024 to implement a plan for the expanded pilot with a broadened
12 scope of customer participation, including EVs and partnering with community choice aggregators,
13 within the broader framework of testing more advanced DER compensation structures that align with
14 grid reliability and the State's objectives around GHG reductions. Enrollment for this pilot will
15 commence on June 1, 2024.

16 In A.20-10-011, the CPUC decision approved PG&E's proposal to establish a pilot program to
17 compensate commercial customers for their vehicle-to-everything (V2X) capabilities, specifically
18 targeting dynamic export rates for EVs.¹⁷⁰ PG&E's proposal sought to implement a pilot program to
19 incentivize commercial customers to participate in V2X activities, thereby enabling their EVs to export
20 energy to the grid during peak demand periods. This would help balance the grid and integrate
21 renewable energy resources more effectively, while also providing potential revenue streams for EV

¹⁶⁶ CPUC Staff Paper on Advanced Demand Flexibility Management and Customer DER Compensation;
<https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/advanced-der---demand-flexibility-management/ed-white-paper---advanced-strategies-for-demand-flexibility-management.pdf>.

¹⁶⁷ D.21-12-015, Ops 59, 60.

¹⁶⁸ D.24-01-32.

¹⁶⁹ D.24-01-032, COL 22.

¹⁷⁰ D.22-10-024.

owners. This is an example of an approved compensation mechanism for exports from EVs in another California IOU territory.

In A.21-12-006, the CPUC approved SDG&E's proposal to establish a pilot program specifically directing the development of an export rate for separately metered electric vehicle charging loads with an aggregated maximum demand of 20 kilowatts or greater (EV-High Power Rate).¹⁷¹ The export rate uses the CAISO day-ahead hourly commodity market price that is based on the hourly location marginal prices at SDG&E's default load aggregation point, with a CPP capacity adder to account for periods of peak constraint. This again represents another example of the CPUC authorizing compensation for V2G exports from EVs in California.

C. Industry Trends

This is the ideal moment in the V2G market's evolution to implement an EV-specific export pricing proposal, particularly given emerging industry trends and readiness indicators. This is due to several factors, including notable technological advancements, customer awareness, and supportive research conducted by entities like SCE, as elaborated below.

First, the increasing availability of bi-directional EVs and Electric Vehicle Supply Equipment (EVSE) marks a key milestone in the V2G landscape. With plans underway for most new EV models to incorporate bi-directional capabilities by 2026,¹⁷² coupled with the commercial availability of bi-directional EVSEs from multiple manufacturers starting in late 2023,¹⁷³ the infrastructure necessary to tap into V2G capabilities is rapidly materializing. This technological, and more broadly market readiness, signals a tangible pathway for enabling bi-directional integration of EVs with the grid. SCE's

¹⁷¹ D.23-11-006.

¹⁷² Explore the Challenges and Opportunities of Bi-Directional Charging and EVs, found at Miguel Tapia, *Explore the challenges and opportunities of bi-directional charging and EVs*, AVNET, (December 7, 2023); available at <https://www.avnet.com/wps/portal/us/resources/article/explore-the-challenges-and-opportunities-of-bi-directional-charging-and-evs/#:~:text=In%20the%20U.S.%2C%20GM%20announced,interface%20and%20charging%20infrastructure%20needed.>

¹⁷³ Bidirectional EV chargers To Finally Materialize in 2024, found at Kelly Pickerel, *Bidirectional EV chargers to finally materialize in 2024*, Power World (January 11, 2024); available at <https://www.solarpowerworldonline.com/2024/01/bidirectional-ev-chargers-to-finally-materialize-in-2024/#:~:text=Bidirectional%20EV%20chargers%20to%20finally%20materialize%20in%202024.>

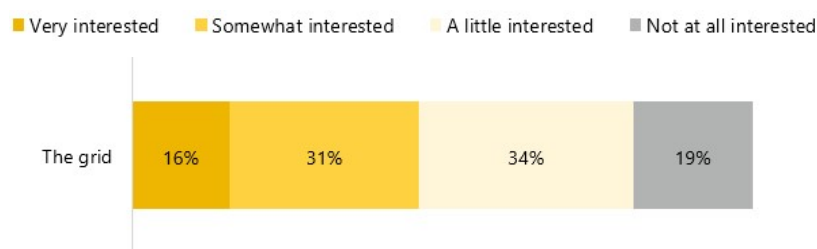
proposal of a time-of-day export pricing mechanism is an important first step within the overall framework of SCE's VGI roadmap.

Second, there exists awareness and a palpable interest among consumers regarding V2G technologies, propelled in part by media coverage and public discourse surrounding their potential benefits. As evidenced by the prevalence of V2G-related articles and headlines in mainstream news outlets, customers are increasingly cognizant of the transformative role that their EVs may be able to play in the energy ecosystem, provided the right protocols and mechanisms are in place.¹⁷⁴ This heightened awareness primes the market for the adoption of V2G solutions and underscores the receptivity of consumers to initiatives like the VGRP.

Third, SCE developed and collected customers surveys in 2023 that provide empirical evidence of customer acceptance and appetite for V2G exports, further bolstering the case for the need of a retail program that provides compensation for V2G energy exports. As shown below in Figure IX-11, with 81 percent of surveyed customers expressing at least "a little interested" in selling stored energy from their EV batteries back to the grid, there exists a substantial reservoir of demand waiting to be tapped. This robust level of customer interest validates the viability of V2G solutions and underscores the alignment between customer preferences and the objectives of the proposed VGRP model.

¹⁷⁴ Electric Vehicle Market Fuels Innovations, found at Electric Vehicle Market Fuels Innovations | TechLink (techlinkcenter.org), techlinkcenter.org/news/electric-vehicle-market-fuels-innovations?utm_term=latest%20innovations%20in%20electric%20vehicles&utm_campaign=Static+Search+Campaigns+-+Topical&utm_source=adwords&utm_medium=ppc&hsa_acc=9779327819&hsa_cam=20190742759&hsa_gpr=153633880229&hsa_ad=675336994747&hsa_src=g&hsa_tgt=kwd-1172447428271&hsa_kw=latest%20innovations%20in%20electric%20vehicles&hsa_mt=b&hsa_net=adwords&hsa_ver=3&gad_source=1&gclid=CjwKCAjwte-vBhBFEiwAQsv_xfJH3iO-J642IJxQGdSHAuHfou7x-WbPRpz2vUsCoik1y1UA9Md62hoCWhAQAvD_BwE.

Figure IX-11
Customer Interest in Providing Power to the Grid

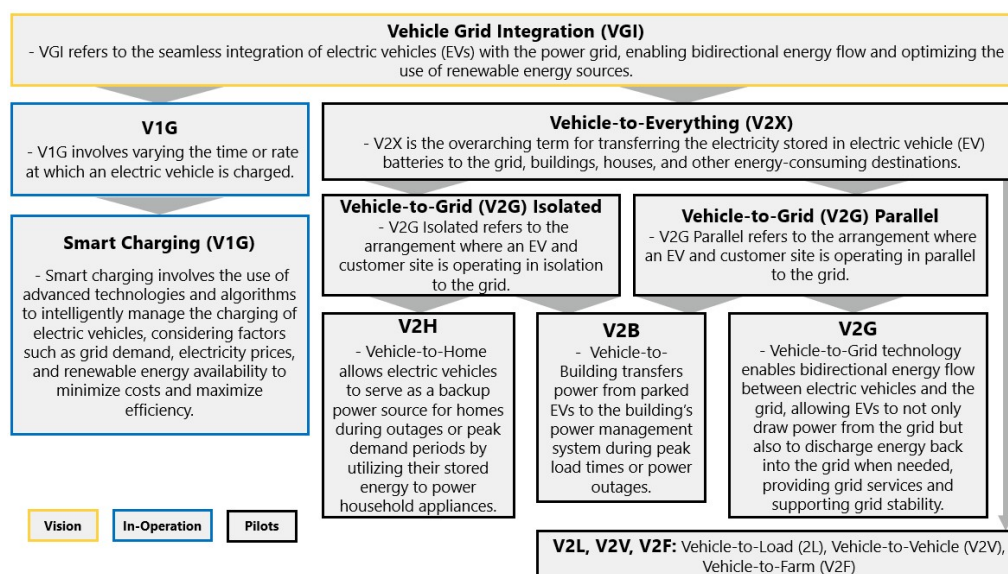


In summary, the convergence of technological advancements, customer awareness, and supportive research indicating customer interest in V2G compensation underscores the timeliness and relevance of implementing a VGRP for V2G exports. By capitalizing on the growing momentum within the V2G market and leveraging insights from SCE’s customer survey, stakeholders can seize the opportunity to accelerate the adoption of V2G technologies and pave the way for a more resilient and sustainable energy future.

1. V2G Alignment With SCE's VGI Strategy

SCE has developed a comprehensive VGI strategy and roadmap that embraces the concepts of V2X and managed charging (V1G). SCE’s multifaceted VGI strategy encompasses various points of interaction between EVs and the grid, each with distinct objectives and benefits, culminating in a concerted effort to optimize the integration of EV resources into the energy ecosystem. Within the scope of V2X, SCE’s strategy relies on pathways that will enable its customers to participate in V2G with the use of their EV. Through a combination of innovative approaches, SCE aims to optimize the utilization of EV resources to support grid stability and reliability, promote energy efficiency, and enhance customer value. The proposed VGRP rate option – a component of SCE’s V2G strategy – is a *grid as a service* pricing mechanism that serves a pivotal role in facilitating the transition towards a decarbonized transportation industry while advancing California’s grid decarbonization goals. Figure IX-12 below, shows the definitions for each of the terms related to VGI and how they work in relation to each other.

Figure IX-12
SCE's Vehicle-Grid-Integration (VGI) Strategy



a) V1G

The first pillar of SCE's VGI strategy, V1G, is fulfilled through three different methods. SCE's V1G strategies underscore the utility's commitment to harnessing the potential of customer EVs as grid-integrated assets. By employing a combination of retail rates, retail DR programs, and direct control mechanisms, SCE not only enhances grid reliability and efficiency but also empowers customers to actively participate in the transition towards a more sustainable and resilient energy future.

(1) Retail Rates

The *first and primary mechanism* employed by SCE for managed charging is Retail Rates. By offering TOU rate plans, SCE incentivizes customers to shape their consumption needs to predetermined peak and non-peak periods that generally reflect the grid's constraints, thereby enhancing customer contributions to the overall cost efficiency of the system. Additionally, SCE's continued partnership and engagement with the CEC and the CPUC in various proceedings on initiatives like the Load Management Standards and SCE's Dynamic Rate Pilot explores advanced strategies in managing flexible demand and DER compensation. The CPUC's CALFUSE framework enables

1 customers to respond dynamically to real-time market signals, further optimizing charging patterns in
2 response to grid conditions.

3 (2) Demand Response

4 The *second mechanism* of SCE's V1G managed charging strategy is Retail
5 DR programs, in which customers participate in DR events when the system experiences peak demand.
6 Programs like ELRP encourage customers to manage consumption and temporarily reduce demand to
7 alleviate the strain on the grid during specific event calls, thereby enhancing grid reliability. While
8 ELRP previously identified a value of \$2 per kWh for V2G energy exports, the CPUC's adaptability in
9 adjusting compensation rates to \$1 per kWh, per the Demand Response Programs, Pilots, and Budgets
10 recent decision,¹⁷⁵ demonstrates its responsiveness to evolving market dynamics.

11 (3) Direct Control

12 The *third mechanism* SCE is developing for V1G managed charging is
13 through the potential option of Direct Control of EV resources through its Distribution Energy
14 Resources Management (DERMs) system. Whether through direct utility control or in collaboration
15 with third-party aggregators, or energy management providers, SCE can remotely manage the charging
16 and discharging of EV batteries to optimize grid operations in real-time. This proactive approach allows
17 SCE to leverage EVs as flexible grid assets, dynamically adjusting their charging profiles to align with
18 system needs while ensuring minimal disruption to customers' mobility requirements.

19 b) V2G - Isolated

20 The *second pillar* in SCE's VGI strategy encompasses one facet of V2X, V2G-
21 Isolated. V2G-Isolated refers to the arrangement where an EV and customer site is operating in isolation
22 from the grid. A common form of V2G-Isolated for customer backup power and resiliency is vehicle-
23 to-home (V2H). By enabling customers to utilize their EVs as energy storage assets for residential and
24 commercial purposes, SCE empowers them to enhance energy resilience, support reliability, and
25 manage electricity costs. A customer can enhance their energy resilience by being able to supply power

¹⁷⁵ D.23-12-005, p. 145.

1 to their site during power outages, or they can manage their electricity costs by avoiding energy
2 consumption from the grid during on-peak hours and instead relying on energy stored in their EV. The
3 strategic alignment between V2H/V2B initiatives and the proposed VGRP mechanism underscores
4 SCE's holistic approach to maximizing the value proposition of EVs in both residential and commercial
5 settings.

6 c) V2G - Parallel

7 Finally, the third pillar of SCE's VGI strategy is promoting the deployment of
8 V2G-Parallel technology, which enables bi-directional flow of energy between customer EVs and the
9 grid. V2G-Parallel refers to the arrangement where an EV and customer site is operating in parallel to
10 the grid and can discharge the EV to support site load or the grid. For business owners, offsetting site
11 load can help with demand charge management during peak periods. Discharging to the grid can help
12 alleviate potential demand-supply imbalances that can exist during the summer peak period. SCE's
13 proposal is committed to leveraging this capability by compensating customers for their vehicle-to-grid
14 exports. Another use case where SCE's proposal could have a meaningful impact on a customer is the
15 integration of school depot charging sites with the grid - School buses typically are in use in the morning
16 and afternoon, but parked and stationary during peak summer hours, positioning them as a prime
17 example of clean energy transportation for children also able to provide grid services and decrease the
18 total cost of ownership for EV buses.

19 d) Additional Considerations

20 While SCE's proposal is a meaningful first step that uses a stable and predictable
21 export price by time-of-day, another approach to enabling V2G is through dynamic retail rates – SCE
22 expects to actively test technology interfaces, settlement and billing processes, and customer
23 engagement portals within the scope of SCE's Dynamic Rate Pilot. While dynamic rates are a robust
24 and more refined approach that can enable V2G, they require complex technology interfaces, billing
25 processes and systems, and need active customer engagement when moderating consumption or
26 discharge preferences on an hourly or sub-hourly basis. Dynamic rates are a tool that will play a
27 meaningful role in managing the grid, but they are not a solution that will cover all use cases and

customer segments. Additional pathways, like VGRP, are therefore needed to offer V2G participation opportunities to a more inclusive and equitable set of customers and use cases.

A non-retail approach that can enable V2G is expected to be aggregating customer EVs for bidding into the CAISO wholesale markets. SCE continues to explore options and identify opportunities where aggregators can integrate customer EVs as resources in the CAISO wholesale market. While wholesale markets can be complex, having robust systems, settlement processes, and customer engagement in place has the potential to unlock how EVs can contribute meaningfully to wholesale market constraints and wholesale grid services.

2. Program Administration

SCE will administer the VGRP by determining customer eligibility and adopting a deployment plan that identifies potential system enhancements and impacts on business processes. It is expected that this option would be available to customers before the Summer 2027 season, if not sooner.

Customers eligible for enrollment in the program include bundled non-lighting Residential, Commercial, Industrial, and Agricultural & Pumping customers. Residential customers enrolled on VGRP will need to subscribe to PRIME or PRIME Plus rate schedules. Residential customers subscribing to a Tiered Rate plan will not be eligible for enrollment in the VGRP. Non-residential customers eligible for SCE's VGRP must be subscribed on a currently available TOU rate plan – any customer on a legacy TOU period rate plan, NEM-Aggregation, NBT-Aggregation, RES-BCT, NEM-V, MASH-VNM, SOMAH, or any other virtual or aggregation pertinent billing arrangements, will not be eligible for enrollment on the VGRP.

Customers currently enrolled in Net Energy Metering (NEM), or Net Billing Tariff (NBT) are eligible to enroll in VGRP. A V2G Net Generation Output Meter (V2G-NGOM) installed on the V2G equipment is required to take service on this option. The V2G-NGOM measures EV discharge and acts in concert with SCE's main retail meter to determine exports from the EV separately from exports from the NEM or NBT eligible resource.

(a) For customers ***without** NEM or NBT eligible systems (solar systems)*, where a bi-directional V2G resource(s) is installed on the customer site, the V2G-NGOM will be used to measure

the EV exports and will prepare the customer for any future NBT installations. In cases where a standalone stationary storage device is also at a customer's site, the V2G-NGOM will enable SCE to ensure only EV exports registered on channel 2 of the primary meter receive the VGRP export credit.

(b) For customers *with NEM or NBT eligible systems¹⁷⁶ (solar systems)* and a bi-directional V2G resource(s), the V2G-NGOM will be used to determine the net basis of exports from the EV during times when both the solar system and the V2G resource are contemporaneously exporting to the grid. Priority and covenants around export restrictions for billing purposes will be applied to the solar system's exports so that the total NEM/NBT eligible exports will not exceed the level of NEM/NBT eligible exports prior to the availability of the V2G resource. This framework recognizes that solar systems are sized to serve onsite energy consumption on an annual basis. The VGRP is structured to not alter the relationship between the NEM or NBT solar system's self-supply of on-site load and exports. Exports tracked on channel 2 of the SCE meter that are in excess of the V2G exports measured by the V2G-NGOM, will be valued at the NEM/NBT export rate. The V2G resource will be compensated at the VGRP export rate.

VGRP structures pricing for exports generally consistent with SCE's current peak and off-peak TOU periods. Seasons are segmented using the same seasonal definitions in retail rates - summer is June through September and winter is October through May. Day-type categorizations for weekday and weekend/holidays will also remain consistent with the retail TOU period definitions. A similar time-of-day categorization of on-peak and off-peak and weekday vs. weekend will also be incorporated. These similar thresholds with the TOU rate structure will both allow for customer familiarity and decrease the complexity and cost of implementation.

D. Key Elements of the Tariff:

Under SCE's VGRP in isolation, all utility delivered energy (Channel 1 consumption measured at the meter) is charged at the retail rate consistent with the covenants of the retail tariff. Exports measured at the meter (Channel 2) are priced at the proposed export compensation rate. The proposed

¹⁷⁶ Eligible NEM or NBT solar systems can be standalone solar systems or paired-storage systems.

1 export compensation price is differentiated by time-of-day and is determined by using specific avoided
2 cost components of the CPUC's Avoided Cost Calculator (ACC), as explained in more detail below.
3 Hourly costs from the ACC for each avoided cost component included in the price are aggregated by
4 day-type (weekday or weekend/holiday), season (summer or winter), and time-of-day periods (on-peak
5 or off-peak) to present a simple, manageable, and stable structure of export prices that is easily
6 understandable by customers as it generally aligns with their current on-peak and off-peak TOU periods
7 on the retail rate and gives them a set and pre-determined period to schedule any potential discharge
8 they may have available from their EVs.

9 For any given year, SCE's export price includes the following five components from the
10 CPUC's ACC: (1) GHG Cap and Trade (Marginal Emissions); (2) Generation Energy; (3) Generation
11 Capacity;¹⁷⁷ (4) Ancillary Services Procurement; and (5) Losses. Because SCE's proposal is intended as
12 a first step on the path to enabling this still nascent market segment, the following ACC components are
13 not included in SCE's V2G export price: (1) GHG Adder (Marginal Emissions); (2) GHG Portfolio
14 Rebalancing; (3) Transmission; (4) Distribution; and (5) Methane Leakage. As the market matures, SCE
15 expects price valuation to further evolve in support of the potential array of services that can be
16 harvested from EV exports to support the grid. Table IX-31 provides a summary of export prices and is
17 based on the most current version of the CPUC's Avoided Cost Calculator.

¹⁷⁷ SCE acknowledges that it may be premature to include the ACC's full generation capacity value in the export price because this program is not yet reflected as a demand modifier in the California Energy Commission's (CEC) demand forecast. SCE proposes to evaluate program performance and work with the CEC going forward to incorporate the impacts of this program in the demand forecast, so that it can be treated consistently with other dynamic rate pricing programs such as Critical Peak Pricing.

Table IX-31
Illustrative VGRP Export Rate (\$/kWh)

Day of Week / Time of Day Segmentation	Seasonal Segmentation	
	Summer (June – Sept)	Winter (Oct – May)
Weekday – Off-Peak (12 am – 6 pm, 9 pm – 12 am)	\$ 0.05 / kWh	\$ 0.04 / kWh
Weekday – On-Peak (6 pm – 9 pm)	\$ 0.58 / kWh	\$ 0.06 / kWh
Weekend – Off-Peak (12 am – 6 pm, 9 pm – 12 am)	\$ 0.05 / kWh	\$ 0.04 / kWh
Weekend – On-Peak (6 pm – 9 pm)	\$ 0.51 / kWh	\$ 0.06 / kWh

Table IX-32 below provides an estimate of the credits a customer may earn through exported energy under the proposed VGRP rate option. The estimates assume a customer is on SCE's PRIME rate plan and charging their EV during Off-peak hours (currently about \$0.26 per-kWh in the Summer). The customer is assumed to export for the entire three-hour On-peak period with 85 percent round trip efficiency at a steady state of the noted kW-per-hour. SCE's estimates assume exports only during the summer On-peak period, since that is currently the period where energy is potentially most needed on the grid, and the export price provides some financial benefit for exporting energy when compared to the Off-peak retail charging rate. The estimates also assume that a residential customer will first offset the average summer total site load of 6.75 kWh on a weekday and 6.73 kWh on a weekend for the time-period from 6 – 9 p.m. before exporting to the grid and earning credits through VGRP. The customer's annual estimated credits earned through VGRP will be displayed on their SCE bill as an independent line item that has the potential to carry over to the next month in cases where more credits are earned than energy consumption charges are accrued. VGRP credits may carry over month-to-month, however, will not be applied to non-energy and non-bypassable charges. The VGRP credits will also not carry over into a new calendar year. Any credits left over after December 31st will be forfeited. Since only summer months currently provide a compensation level attractive for exports, it

is unlikely and expected to be rare that VGRP credits earned in the summer are not offset by consumption in October, November, and December.

Table IX-32
Annual Customer Estimated Credit

Summer On-Peak Credit – Based on Discharge (\$)	EVSE Export Levels (kW)		
	6.6 kW	9.6 kW	19.2 kW
1 Day per Week for 3 hours / Day	\$ 55	\$ 96	\$ 230
2 Days per Week for 3 hours / Day	\$ 110	\$ 193	\$ 459
3 Days per Week for 3 hours / Day	\$ 164	\$ 289	\$ 689
4 Days per Week for 3 hours / Day	\$ 219	\$ 386	\$ 918
5 Days per Week for 3 hours / Day	\$ 274	\$ 482	\$ 1,148
6 Days per Week for 3 hours / Day	\$ 317	\$ 558	\$ 1,328
7 Days per Week for 3 hours / Day	\$ 360	\$ 634	\$ 1,509

SCE recommends that the CPUC require customers utilizing this VGRP rate option to interconnect their systems under the terms and conditions of SCE’s Electric Rule 21. EVs or other eligible devices would be required to use authorized inverters with approved Underwriters Laboratories (UL) certifications in accordance with Rule 21. SCE is also recommending that the interconnection costs for these systems, if not already paired with a NEM/NBT eligible system, be treated in the same manner as is currently being done for NEM/NBT systems (i.e., systems less than 1 MW will not be required to pay for system upgrades triggered by the interconnection) and would follow the current process that NEM/NBT customers use when applying for interconnection. SCE is currently using a streamlined process to review NEM/NBT applications through its PowerClerk (PCI) portal. SCE has been able to process 10,000+ applications per month through PCI and believes DERs requesting interconnection through VGRP would be best served using this streamlined process in PCI. VGRP devices would help the grid and decrease system costs by supporting grid resiliency and promoting electrification.

1 With the understanding that grid needs may continue to evolve, and V2G capabilities are
2 currently nascent, SCE plans to do an annual review to look at customer exports and participation rates
3 in aggregate through VGRP. Data and derived insights will support refinement of VGRP and future
4 modifications and adjustments to the rate rider in order to navigate an evolving ecosystem of energy
5 exchange and ensure both customers and the grid maximize the value of EVs as grid integrated
6 resources.

7 **E. Marketing, Education, and Outreach**

8 SCE will play a crucial role in marketing, education, and outreach (ME&O) efforts for VGRP.
9 SCE has a unique opportunity to promote sustainable transportation solutions and drive adoption of EVs
10 while managing grid dynamics effectively. SCE aims to effectively educate and engage both residential
11 and non-residential customers on the benefits and functionalities of VGRP.

12 Initially, the idea of exporting energy from an EV may be new and not previously considered,
13 requiring the introduction of the potential capabilities of EVs to customers. SCE will strive to educate
14 both new EV customers and current owners of EVs on the idea of EV exports and the new program
15 through creating awareness and education opportunities. SCE may initiate comprehensive marketing
16 campaigns to raise awareness about VGRP among its residential and non-residential customers. This
17 could involve various channels such as digital advertising, social media engagement, and/or traditional
18 media outlets. Educating potential and new EV customers on how the program can expand the use of
19 EVs beyond transportation, and decrease total cost of ownership, will support EV adoption and
20 participation in VGRP.

21 SCE will also develop educational materials that may include pages on its website, brochures,
22 online tutorials, and/or workshops to explain the details of the rate structure, how EV charging and
23 exporting interact with the grid, and the importance of managing energy consumption during peak
24 demand periods. By empowering customers with knowledge, SCE can encourage informed decision-
25 making and active participation in the program.

26 Outreach efforts should extend beyond existing customers to reach potential EV owners and
27 community stakeholders. SCE may collaborate with local governments, environmental organizations,

1 automotive dealerships, and EV advocacy groups to host outreach events, participate in community
2 forums, and sponsor EV-related initiatives. Building partnerships with key stakeholders can amplify the
3 reach of SCE's messaging and foster a supportive ecosystem for EV adoption and grid integration.

4 Moreover, SCE can leverage data analytics and customer feedback mechanisms to continuously
5 refine its marketing, education, and outreach strategies. By tracking customer engagement metrics,
6 understanding evolving market trends, and soliciting input from stakeholders, SCE can adapt its
7 approach to effectively address the needs and preferences of its target audience.

8 Overall, through strategic marketing, education, and outreach efforts, SCE can fulfill its role in
9 promoting VGRP and driving the transition to a cleaner, more sustainable transportation future in
10 Southern California. By engaging and empowering customers, building strong partnerships, and
11 embracing innovation, SCE can maximize the impact of its VGRP and contribute to a more resilient and
12 environmentally responsible energy system.

13 **F. Conclusion**

14 In conclusion, SCE's proposal is a meaningful first step needed to stimulate and promote broader
15 adoption of technologies that integrate customer EVs with the grid. SCE's proposal presents customers
16 with a pricing structure based on pre-determined time-of-day pricing periods, much like the TOU
17 periods customers have grown accustomed to, on their otherwise applicable retail rate. This allows
18 customers to align their discharge preferences within stable, predictable, and manageable pricing
19 periods. SCE's comprehensive VGI strategy, which incorporates the proposed VGRP, lays the
20 foundation for unlocking the full potential of EVs as grid-integrated assets.

21 VGRP is not intended to be the pathway for all customers to participate in V2G, and it is not
22 identified as the tool to address all V2G use cases. However, VGRP has been identified as one pillar in
23 SCE's broader V2G and VGI strategy, by creating a pathway for a meaningful segment of SCE's
24 customer base. In addition to VGRP being an important tool in managing our future grid, the current
25 market transformation and availability of bi-directional EVs and EVSEs make this the opportune time
26 for the development of VGRP. By incentivizing customer participation in V2G, *grid-as-a-service*
27 exports and providing a transparent compensation mechanism, SCE paves the way for a sustainable and

- 1 resilient energy future while empowering customers to actively contribute to grid decarbonization efforts
- 2 and manage their energy bills.

Appendix A

Glossary Of Terms

AMI: Advanced Metering Infrastructure. Systems that measure, collect and analyze interval energy usage from advanced devices such as electricity meters, gas meters, and/or water meters, through various communication media on request or on a pre-defined schedule. This infrastructure includes hardware, software, communications, customer associated systems and meter data management software.

Avoided Cost Calculator (ACC): an Excel-based spreadsheet model produced by Energy + Environmental Economics, Inc. (E3) for use in demand-side cost effectiveness proceedings at the California Public Utilities Commission (CPUC).

Baseline Allowances: Baseline allowances are established levels of kWh provided to residential customers. Under Public Utilities Code Section 739, baseline allowances represent the electricity necessary to supply a significant portion (50 to 60 percent) of the reasonable needs of the average residential customer. Increased baseline allowances are provided to all-electric customers and those customers who have the specific medical needs identified in Public Utilities Code Section 739.

Basic Charge: A monthly, fixed charge. The Basic Charge is designed to recover a portion of SCE's marginal customer costs, such as customer hookup facilities and revenue cycle services, which do not vary with energy usage.

Bundled Service: Retail service by SCE to customers who also receive energy from SCE.

Budget Billing Plan (BPP): A billing option in which an estimated annual bill is applied as 12 equal monthly bills, and incorporating periodic true ups.

CARE: California Alternate Rates for Energy. A program for low-income households that offers qualified customers a discount of approximately 32.5 percent off their electric bill.

Coincident Peak Demand: A customer or customer group's energy demand during periods of peak system demand.

CCA: Community Choice Aggregation. A system incorporated into state law that allows cities, counties, and joint power authorities to aggregate the load of individual customers within a defined jurisdiction in order to procure their energy needs from alternative energy sources.

Cost Responsibility Surcharge (CRS): A surcharge, generally applied to DA, CCA or other customers receiving energy from suppliers other than SCE, for recovery of costs associated with DWR power purchases or above-market costs of utility generation.

Competition Transition Charge (CTC): A charge for recovery of costs, delineated in Public Utilities Code Sections 367 and 368 of AB 1890, which were defined to be uneconomic as a result of the restructuring of electric industry.

Critical Peak Pricing (CPP): An extension of TOU pricing that applies a special, increased rate structure on select days when demand is predicted to be high, in an attempt to reduce demand when it is most critical.

Customer Charge: See Basic Charge.

Demand Charge: A charge for electric service based on the customer's maximum kW demand during the billing or TOU period.

Demand Response: Refers to mechanisms for managing customer demand in response to supply conditions, for example, having electricity customers reduce their consumption during system emergencies and peak demand conditions, or in response to high market prices.

Design Demand: The amount of delivery capacity (in kW) that is necessary to reliably expand service to an additional customer or group of customers.

Design Demand Marginal Cost: The opportunity cost associated with providing additional capacity on the T&D system to deliver electricity to consumers.

Direct Access (DA) Service: Retail service by SCE to customers who purchase energy from a service provider other than SCE.

Distributed Energy Resource (DER): Geographically dispersed generation resources that include solar, combined heat and power (CHP), located on the distribution system.

Distribution Energy Resources Management System (DERMs): A software platform used to manage a group of DER assets, such as solar, EVs, etc.

Distributed Generation (DG): A form of electric generation smaller in size than a traditional central station power plant. A DG unit may be connected directly to a customer's facilities (on-site) or

on a utility's distribution system (on-grid).

Distribution System: The portion of the electrical system (50 kV and below) that distributes electric energy from convenient points on the transmission system to consumers. The components making up the distribution system are either demand-related components or customer-related (including grid infrastructure) components.

Diversity Benefit Adjustment (DBA): Performed to adjust the customer's bill to recognize that a benefit is realized by a master-metered customer who had more sales billed at the lower tiered rates and less at higher tiered rates than were actually used by its sub-metered customers.

Economic Development Rate (EDR): Discounted rate schedules offered to attract, retain, or expand a customers' business operations in SCE's service territory versus out of state.

Equal Percent of Marginal Cost (EPMC): Because marginal cost revenues are not necessarily equal to the utility's revenue requirement, the system revenue requirement is allocated to different rate groups based on the percentage of each rate group's share of the marginal cost revenues.

ERRA: Energy Resources Recovery Account. In ERRA recovery proceedings SCE reconciles and seeks recovery of revenue requirements associated with fuel and purchased power expenses.

Electric Service Provider (ESP): Entity (non-utility) that offers electric service to customers within the service territory of an electric utility.

Electric Vehicle Supply Equipment (EVSE): Device used to charge an electric vehicle.

Facilities-Related Demand (FRD) Charge: A charge applied to customers' monthly peak demands designed to recover certain T&D costs that were defined to be unrelated to system peak or coincident peak usage.

FERC: The Federal Energy Regulatory Commission. The federal agency responsible for regulating wholesale electricity and natural gas markets pursuant to the Federal Power Act of 1935, as amended.

Final Line Transformer (FLT): A transformer that converts primary voltages to service voltages.

Franchise Fee: Municipally imposed licencing fee on a utility, authorizing a utility to operate within the municipal limits. It is generally a percent of revenues.

Fixed Recovery Charge (FRC): SCE has been permitted to issue bonds that enable it to recover more quickly certain costs related to preventing and mitigating catastrophic wildfires, while reducing the total cost to its customers. The FRC has been approved by the CPUC to repay those bonds.

Generating System: The aggregate of electrical generating facilities that may serve the loads in a given area.

Horsepower (hp): An English system measure of power, equivalent to about .75 kW.

ISO (or CAISO): Refers to the California Independent System Operator, a state chartered non-profit corporation with centralized control of the statewide transmission grid, charged with ensuring the efficient use and reliable operation of the transmission system.

Kilowatt-Hour: A basic unit of electrical energy. A kilowatt-hour is equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour ($\text{kWh} = \text{kW} \times \text{hour}$).

Line Loss or Losses: The general term applied to energy (kWh) and capacity (kW) lost during operation of an electric transmission or distribution system. Line losses occur principally as energy transforms from one voltage to another and as energy passes through conductors thereby encountering impedance.

Marginal Costs: The change in total costs of producing a product due to a small change in the quantity produced.

Marginal Cost Revenues: The revenues that would result if various components of electric service were priced to reflect the marginal costs of providing such component services.

Marginal Generation Costs: The change in total costs associated with providing an additional unit of energy and dependable capacity from the generating system at any given moment.

Marginal Transmission Costs: The change in total costs associated with transmission facilities due to a small change in the design demand cost driver.

Master-Meter: A meter that registers the energy consumption of two or more residences, apartment dwellings, offices, etc. (considered a single service).

Medical Baseline: A kWh allowance, in addition to the standard baseline allowance, available to domestic customers utilizing medical equipment on residential electric service.

Non-bypassable Charges (NBCs): Include the NDC, PPC, WFC, and the PUCRF.

Net Billing Tariff (NBT) or Solar Billing Plan (SBP): A new program for customers who apply for interconnection of an eligible renewable generating system, such as solar or wind, after April 14, 2023. The Solar Billing Plan succeeds the Net Energy Metering (NEM) 2.0 program.

Net Generation Output Meter (NGOM): Measures EV or non-solar panel generation production.

OAT: Otherwise Applicable Tariff. The customer's regularly filed rate schedule under which service is rendered.

Peak Demand or Maximum Demand: A customer's highest demand recorded over a specified length of time, *e.g.*, 15 minutes, but without regard to any given initial time.

Peak Period: The time of day and season when energy demand is expected to be the greatest.

Peak Load Risk Factor (PLRF): A deterministic approach that computes the relative ratio of peak load at risk in a given hour to the sum of hourly peak load at risk in a modeled year. The PLRF assigns peak-capacity-related design demand marginal costs to TOU periods.

Power Charge Indifference Adjustment (PCIA): A mechanism adopted by the Commission as part of a ratemaking methodology developed to ensure that when electric customers of an IOU depart from IOU service and receive their electricity from a non-IOU provider, those customers remain responsible for costs previously incurred on their behalf by the IOUs.

Power Factor: A measure of efficiency of an electric system and defined as the ratio of true power (watts) to the apparent power (voltage x current).

Primary Voltage: Facilities at which electric power is taken or delivered, generally between and including 2 kV and 50 kV.

Ramp: The relative change in hourly load over a predefined period of time.

Revenue Allocation: The process of assigning authorized revenue requirement to rate groups.

Revenue Requirement: The costs of providing utility services that the Commission has determined are appropriate to recover through customer rates.

RTP: Real Time Pricing. Pricing system where electricity prices may change as often as hourly. The price signal is provided to the user on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level.

SDP: Summer Discount Plan. A program that offers participating customers credits on their summer season bills in exchange for allowing the utility to install a remotely controlled cycling device on their air conditioner(s). The cycling device permits the utility to periodically turn off, or "cycle," a customer's air conditioner(s) for short periods during the height of the summer season.

Secondary Voltage: Facilities at which electric power is taken or delivered, generally between 120 and 480 volts at the customer premises, up to 2 kV.

Service Voltage: Primary-voltage service customers take delivered-energy at voltages between and including 2 kV and 50 kV. If energy is delivered at less than 2 kV, the customer is defined as a secondary-voltage service customer, and if energy is delivered at greater than 50 kV, the customer is defined as a subtransmission-voltage service customer.

SmartConnect Meter: Advanced meter technology with enhanced data collection and communication capabilities.

Streetlight Facilities: Equipment dedicated to the exclusive use of streetlight customers. For SCE-owned street lighting systems, facilities include the pole and luminaire. For customer-owned street lighting systems, facilities may include switching equipment and specialized transformers.

Subtransmission Voltage: Facilities at which electric power is taken or delivered, generally greater than or equal to 66 kV and less than 220 kV.

Tiers: Blocks of energy consumption for Domestic service, for which different energy charges apply, defined in terms of the applicable baseline allowances.

Time Management Load Controller (TMLC) Device: Device that allows Agricultural and Pumping customers to automatically interrupt the operation of their customer-owned equipment during the on-peak period.

Time-Related Demand (TRD) Charge: A peak demand charge that is generally designed to recover distribution peak and generation peak capacity costs

Transformer Capacity: The nameplate rating of an electrical transformer, usually expressed in kV.

Transmission System: The transmission and sub-transmission systems transport electric energy in bulk (above 50 kV) from the source of supply (generating system) to other parts of the utility system or to other utilities.

URG: Utility Retained Generation. Refers to generation assets that are owned by the utility.

Wildfire Fund Charge (WFC): Non-bypassable charge that is recovered from customers in the same manner as the DWR bond charge was.

Appendix B

Present And Proposed Rates

			October 2023 Rates			Proposed 2025 GRC Rates					
			Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
D	Energy Charge- \$/kWh										
	Baseline - Summer		0.16530	0.16540	0.33070	0.17567	0.17741	0.35308	6.3%	7.3%	6.8%
	- Winter		0.16530	0.16540	0.33070	0.17567	0.17741	0.35308	6.3%	7.3%	6.8%
	101% - 130% of Baseline - Summer		0.25974	0.16540	0.42514	0.27806	0.17741	0.45547	7.1%	7.3%	7.1%
	- Winter		0.25974	0.16540	0.42514	0.27806	0.17741	0.45547	7.1%	7.3%	7.1%
	131% - 200% of Baseline - Summer		0.25974	0.16540	0.42514	0.27806	0.17741	0.45547	7.1%	7.3%	7.1%
	- Winter		0.25974	0.16540	0.42514	0.27806	0.17741	0.45547	7.1%	7.3%	7.1%
	201% - 400% of Baseline - Summer		0.25974	0.16540	0.42514	0.27806	0.17741	0.45547	7.1%	7.3%	7.1%
	- Winter		0.25974	0.16540	0.42514	0.27806	0.17741	0.45547	7.1%	7.3%	7.1%
	Over 400% of Baseline - Summer		0.25974	0.16540	0.42514	0.27806	0.17741	0.45547	7.1%	7.3%	7.1%
	- Winter		0.25974	0.16540	0.42514	0.27806	0.17741	0.45547	7.1%	7.3%	7.1%
	Basic Charge - \$/day										
	Single-Family Residence		0.031		0.031	0.031		0.031	0.0%		0.0%
	Multi-Family Residence		0.024		0.024	0.031		0.031	29.2%		29.2%
	Minimum Charge - \$/day										
	Single Family Residence		0.346		0.346	0.346		0.346	0.0%		0.0%
	Multi-Family Residence		0.346		0.346	0.346		0.346	0.0%		0.0%
	Minimum Charge (Medical Baseline) - \$/day										
	Single Family Residence		0.173		0.173	0.173		0.173	0.0%		0.0%
	Multi-Family Residence		0.173		0.173	0.173		0.173	0.0%		0.0%
	California Climate Credit		(71.00)		(71.00)	(71.00)		(71.00)	0.0%		0.0%
	Smart Energy Program (SEP)										
	Energy Payment - \$/kWh			0.00000	0.00000	(0.07000)	0.00000	(0.07000)			
	Capacity Payment - \$/summer day		(0.328)	0.0000	(0.328)	(0.328)	0.000	(0.328)	0.2%		0.2%
D-CARE	Energy Charge - \$/kWh										
	Baseline - Summer		0.05873	0.16540	0.22413	0.06092	0.17741	0.23833	3.7%	7.3%	6.3%
	- Winter		0.05873	0.16540	0.22413	0.06092	0.17741	0.23833	3.7%	7.3%	6.3%
	101% - 130% of Baseline - Summer		0.12018	0.16540	0.28558	0.13003	0.17741	0.30744	8.2%	7.3%	7.7%
	- Winter		0.12018	0.16540	0.28558	0.13003	0.17741	0.30744	8.2%	7.3%	7.7%
	131% - 200% of Baseline - Summer		0.12018	0.16540	0.28558	0.13003	0.17741	0.30744	8.2%	7.3%	7.7%
	- Winter		0.12018	0.16540	0.28558	0.13003	0.17741	0.30744	8.2%	7.3%	7.7%
	201% - 400% of Baseline - Summer		0.12018	0.16540	0.28558	0.13003	0.17741	0.30744	8.2%	7.3%	7.7%
	- Winter		0.12018	0.16540	0.28558	0.13003	0.17741	0.30744	8.2%	7.3%	7.7%
	Over 400% of Baseline - Summer		0.12018	0.16540	0.28558	0.13003	0.17741	0.30744	8.2%	7.3%	7.7%
	- Winter		0.12018	0.16540	0.28558	0.13003	0.17741	0.30744	8.2%	7.3%	7.7%
	Basic Charge - \$/day										
	Single-Family Residence		0.024		0.024	0.024		0.024	0.0%		0.0%
	Multi-Family Residence		0.018		0.018	0.025		0.025	38.9%		38.9%
	Minimum Charge - \$/day										
	Single Family Residence		0.173		0.173	0.173		0.173	0.0%		0.0%
	Multi-Family Residence		0.173		0.173	0.173		0.173	0.0%		0.0%
	California Climate Credit		(71.00)		(71.00)	(71.00)		(71.00)	0.0%		0.0%
	Smart Energy Program (SEP)										
	Energy Payment - \$/kWh			0.00000	0.00000	(0.07000)	0.00000	(0.07000)			
	Capacity Payment - \$/summer day		(0.328)	0.0000	(0.328)	(0.328)	0.000	(0.328)	0.2%		0.2%
D-SDP	Air Conditioning Cycling										
	Credit - \$/ton/summer season day										
	50% Cycling		(0.164)		(0.164)	(0.164)		(0.164)	0.0%		0.0%
	100% Cycling		(0.328)		(0.328)	(0.328)		(0.328)	0.0%		0.0%
D-SDP-O	Air Conditioning Cycling										
	Credit - \$/ton/summer season day										
	50% Cycling		(0.083)		(0.083)	(0.083)		(0.083)	0.0%		0.0%
	100% Cycling		(0.164)		(0.164)	(0.164)		(0.164)	0.0%		0.0%
DE	Discount - %		25%		25%	25%		25%	0.0%		0.0%

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October 2023 Rates		
Delivery	Generation	Total Rate

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

Delivery Change	Generation Change	Total Rate Change

D-FERA

Energy Charge - \$/kWh

Baseline - Summer
 - Winter
101% - 130% of Baseline - Summer
 - Winter
131% - 200% of Baseline - Summer
 - Winter
201% - 400% of Baseline - Summer
 - Winter
Over 400% of Baseline - Summer
 - Winter

0.10577 0.16540 0.27117
 0.10577 0.16540 0.27117
 0.18322 0.16540 0.34862
 0.18322 0.16540 0.34862
 0.18322 0.16540 0.34862
 0.18322 0.16540 0.34862
 0.18322 0.16540 0.34862
 0.18322 0.16540 0.34862

0.11212 0.17741 0.28953
 0.11212 0.17741 0.28953
 0.19608 0.17741 0.37349
 0.19608 0.17741 0.37349
 0.19608 0.17741 0.37349
 0.19608 0.17741 0.37349
 0.19608 0.17741 0.37349
 0.19608 0.17741 0.37349

6.0% 7.3% 6.8%
 6.0% 7.3% 6.8%
 7.0% 7.3% 7.1%
 7.0% 7.3% 7.1%
 7.0% 7.3% 7.1%
 7.0% 7.3% 7.1%
 7.0% 7.3% 7.1%
 7.0% 7.3% 7.1%

Basic Charge - \$/day

Single-Family Residence
 Multi-Family Residence

0.025 0.025
 0.020 0.020

0.025 0.025
 0.025 0.025

0.0% 0.0%
 25.0% 25.0%

Minimum Charge - \$/day

Single Family Residence
 Multi-Family Residence

0.173 0.173
 0.173 0.173

0.173 0.173
 0.173 0.173

0.0% 0.0%
 0.0% 0.0%

California Climate Credit

(71.00) (71.00)

(71.00) (71.00)

0.0% 0.0%

Smart Energy Program (SEP)

Energy Payment - \$/kWh
 Capacity Payment - \$/summer day

0.00000 0.00000
 0.0000 0.0000

(0.07000) 0.00000 (0.07000)
 (0.328) 0.0000 (0.328)

DM

Diversity Adjustment - \$/unit/day

0.084 0.084

0.073 0.073

-13.1% -13.1%

Agricultural Employee Housing

Discount - %

-28.90% -28.90%

-28.90% -28.90%

0.0% 0.0%

DMS-2

Submeter Discount - \$/unit/day

(0.303) (0.303)

(0.426) (0.426)

40.6% 40.6%

Diversity Adjustment - \$/unit/day

0.084 0.084

0.073 0.073

-13.1% -13.1%

Basic Charge Adjustment - \$/unit/day

0.024 0.024

0.031 0.031

29.2% 29.2%

Basic Charge Adjustment CARE - \$/unit/day

0.018 0.018

0.025 0.025

38.9% 38.9%

Basic Charge Adjustment FERA - \$/unit/day

0.020 0.020

0.025 0.025

25.0% 25.0%

TOU-D-Rate A

Energy Charge - \$/kWh

Summer Season - On-Peak
 Off-Peak
 Super-Off-Peak

0.46761 0.38226 0.84987
 0.35722 0.15966 0.51688
 0.09980 0.11247 0.21227

0.49095 0.23713 0.72808
 0.37199 0.19779 0.56978
 0.11153 0.16090 0.27243

5.0% -38.0% -14.3%
 4.1% 23.9% 10.2%
 11.8% 43.1% 28.3%

Winter Season - On-Peak
 Off-Peak
 Super-Off-Peak

0.31175 0.22707 0.53882
 0.30026 0.12159 0.42185
 0.09619 0.11506 0.21125

0.32968 0.31267 0.64235
 0.32283 0.11125 0.43408
 0.10731 0.14061 0.24792

5.8% 37.7% 19.2%
 7.5% -8.5% 2.9%
 11.6% 22.2% 17.4%

Basic Charge - \$/day

Single-Family Residence
 Multi-Family Residence

0.031 0.000 0.031
 0.024 0.000 0.024

0.031 0.000 0.031
 0.031 0.000 0.031

0.0% 0.0%
 29.2% 29.2%

Minimum Charge - \$/day

Single Family Residence
 Multi-Family Residence

0.346 0.000 0.346
 0.346 0.000 0.346

0.346 0.000 0.346
 0.346 0.000 0.346

0.0% 0.0%
 0.0% 0.0%

Minimum Charge (Medical Baseline) - \$/day

Single Family Residence
 Multi-Family Residence

0.173 0.173
 0.173 0.173

0.173 0.173
 0.173 0.173

0.0% 0.0%
 0.0% 0.0%

California Climate Credit

(71.00) 0.00 (71.00)

(71.00) 0.00 (71.00)

0.0% 0.0%

Baseline Credit - \$/kWh

(0.09444) 0.00000 (0.09444)

(0.10239) 0.00000 (0.10239)

8.4% 8.4%

California Alternate Rates for

Energy Discount - %
 Family Electric Rate Assistance Discount - %

100% 100.00%
 100% 100.00%

29% 29%
 18% 18%

-71.1% -71.1%
 -82.0% -82.0%

Smart Energy Program (SEP)

Energy Payment - \$/kWh
 Capacity Payment - \$/summer day

0.00000 0.00000
 (0.328) 0.0000 (0.328)

(0.07000) 0.00000 (0.07000)
 (0.328) 0.0000 (0.328)

0.2% 0.2%

	October 2023 Rates			Proposed 2025 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-D-Rate B									
Energy Charge - \$/kWh									
Summer Season - On-Peak	0.22905	0.57299	0.80204	0.24921	0.43439	0.68360	8.8%	-24.2%	-14.8%
Off-Peak	0.16659	0.15960	0.32619	0.18204	0.19779	0.37983	9.3%	23.9%	16.4%
Super-Off-Peak	0.09756	0.06185	0.15941	0.10900	0.06442	0.17342	11.7%	4.2%	8.8%
Winter Season - On-Peak	0.22905	0.20710	0.43615	0.24921	0.39146	0.64067	8.8%	89.0%	46.9%
Off-Peak	0.16659	0.12160	0.28819	0.18204	0.11125	0.29329	9.3%	-8.5%	1.8%
Super-Off-Peak	0.09756	0.06328	0.16084	0.10900	0.05630	0.16530	11.7%	-11.0%	2.8%
Customer Charge - \$/day	0.731	0.000	0.731	0.674	0.000	0.674	-7.8%		-7.8%
Single-Family Residence									
Multi-Family Residence									
California Alternate Rates for									
Energy Discount - %	100%		100.00%	29%		29%	-71.1%		-71.1%
Family Electric Rate Assistance Discount - %	100%			18%		18%	-82.0%		
Smart Energy Program (SEP)									
Energy Payment - \$/kWh		0.00000	0.00000	(0.07000)	0.00000	(0.07000)			
Capacity Payment - \$/summer day		0.0000	0.0000	(0.328)	0.0000	(0.328)			
California Climate Credit	(71.00)	0.00	(71.00)	(71.00)	0.00	(71.00)	0.0%		0.0%
TOU-D-Rate PRIME									
Energy Charge - \$/kWh									
Summer Season - On-Peak	0.23217	0.42865	0.66082	0.24581	0.47124	0.71705	5.9%	9.9%	8.5%
Mid-Peak	0.23217	0.15255	0.38472	0.24581	0.16771	0.41352	5.9%	9.9%	7.5%
Off-Peak	0.15599	0.10185	0.25784	0.16389	0.11197	0.27586	5.1%	9.9%	7.0%
Winter Season - Mid-Peak	0.23780	0.36108	0.59888	0.21584	0.37266	0.58850	-9.2%	3.2%	-1.7%
Off-Peak	0.14936	0.08649	0.23585	0.13870	0.08926	0.22796	-7.1%	3.2%	-3.3%
Super-Off-Peak	0.14936	0.08649	0.23585	0.13870	0.08926	0.22796	-7.1%	3.2%	-3.3%
Customer Charge - \$/day	0.429	0.000	0.429	0.674	0.000	0.674	57.1%		57.1%
Single-Family Residence									
Multi-Family Residence									
EV Meter Credit (Separately Metered EV Option)	-0.324	0.000	(0.324)	-0.591	0.000	-0.591	-82.4%		-82.4%
EV Submeter Credit - \$/Meter/Day	-0.112		(0.112)	-0.081	0.000	-0.081	27.7%		27.7%
California Alternate Rates for									
Energy Discount - %	100%		100.00%	29%		29%	-71.1%		-71.1%
Family Electric Rate Assistance Discount - %	100%		100.00%	18%		18%	-82.0%		-82.0%
Medical Baseline Credit - % Discount				100%	0%	100%			
Smart Energy Program (SEP)									
Energy Payment - \$/kWh		0.00000	0.00000	(0.07000)	0.00000	(0.07000)			
Capacity Payment - \$/summer day		0.0000	0.00000	(0.328)	0.0000	(0.328)			
California Climate Credit	(71.00)	0.00	(71.00)	(71.00)	0.00	(71.00)	0.0%		0.0%
TOU-D-PRIME-DMD									
Energy Charge - \$/kWh									
Summer Season - On-Peak				0.17100	0.48506	0.65606			
Mid-Peak				0.17100	0.17263	0.34363			
Off-Peak				0.14183	0.11525	0.25708			
Winter Season - Mid-Peak				0.11106	0.32115	0.43222			
Off-Peak				0.11047	0.12209	0.23255			
Super-Off-Peak				0.11107	0.07538	0.18645			
Basic Charge - \$/day									
Single-Family Residence				1.072	0.000	1.072			
Multi-Family Residence				1.072	0.000	1.072			
EV Meter Credit (Separately Metered EV Option)				(0.591)	0.000	(0.591)			
EV Submeter Credit - \$/Meter/Day				(0.081)	0.000	(0.081)			
Time Related Demand Charge - \$/kW									
Summer Season									
On-Peak				3.18	0.00	3.18			
Mid-Peak									
Winter Season									
Mid-Peak				2.62	0.00	2.62			
California Alternate Rates for									
Energy Discount - %				29%	0%	29%			
Family Electric Rate Assistance Discount - %				18%	0%	18%			
Medical Baseline Credit - % Discount				100%	0%	100%			
Smart Energy Program (SEP)									
Energy Payment - \$/kWh				(0.070000)	0.000000	(0.070000)			

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Capacity Payment - \$/summer day

October 2023 Rates		
Delivery	Generation	Total Rate

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate
(0.328)	0.000	(0.328)

Delivery Change	Generation Change	Total Rate Change

TOU-Default-1 (4-9pm)

Energy Charge - \$/kWh

Summer Season - On-Peak	0.29407	0.30239	0.59646	0.32338	0.34062	0.66400	10.0%	12.6%	11.3%
Mid-Peak	0.29407	0.18991	0.48398	0.32338	0.21392	0.53730	10.0%	12.6%	11.0%
Off-Peak	0.25049	0.12272	0.37321	0.27447	0.13823	0.41270	9.6%	12.6%	10.6%
Winter Season - Mid-Peak	0.29407	0.23238	0.52645	0.30870	0.23873	0.54743	5.0%	2.7%	4.0%
Off-Peak	0.25049	0.14871	0.39920	0.26252	0.15277	0.41529	4.8%	2.7%	4.0%
Super-Off-Peak	0.23480	0.12778	0.36258	0.24590	0.13127	0.37717	4.7%	2.7%	4.0%

Basic Charge - \$/day

Single-Family Residence	0.031	0.000	0.031	0.031	0.000	0.031	0.0%		0.0%
Multi-Family Residence	0.024	0.000	0.024	0.031	0.000	0.031	29.2%		29.2%

Minimum Charge - \$/day

Single Family Residence	0.346	0.000	0.346	0.346	0.000	0.346	0.0%		0.0%
Multi-Family Residence	0.346	0.000	0.346	0.346	0.000	0.346	0.0%		0.0%

Minimum Charge (Medical Baseline) - \$/day

Single Family Residence	0.173	0.000	0.173	0.173	0.000	0.173	0.0%		0.0%
Multi-Family Residence	0.173	0.000	0.173	0.173	0.000	0.173	0.0%		0.0%

California Climate Credit

(71.00)	0.00	(71.00)	(71.00)	0.00	(71.00)	0.0%		0.0%
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Baseline Credit - \$/kWh

(0.09443)	0.00000	(0.09443)	(0.10239)	0.00000	(0.10239)	8.4%		8.4%
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California Alternate Rates for

Energy Discount - %	100%	100%	29%	29%	-71.1%	-71.1%
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Family Electric Rate Assistance Discount - %

100%	100%	18%	18%	-82.0%	-82.0%
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Smart Energy Program (SEP)

Energy Payment - \$/kWh	0.00000	0.00000	(0.07000)	0.00000	(0.07000)
Capacity Payment - \$/summer day	0.0000	0.0000	(0.328)	0.0000	(0.328)

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October 2023 Rates		
Delivery	Generation	Total Rate

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

Delivery Change	Generation Change	Total Rate Change
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TOU-Default-2 (5-8pm)

Energy Charge - \$/kWh

Summer Season - On-Peak

0.29637 0.44806 0.74443

0.32437 0.50778 0.83215

9.4% 13.3% 11.8%

Mid-Peak

0.29637 0.26068 0.55705

0.32437 0.29542 0.61979

9.4% 13.3% 11.3%

Off-Peak

0.25723 0.11414 0.37137

0.28070 0.12935 0.41005

9.1% 13.3% 10.4%

Winter Season - Mid-Peak

0.29637 0.32005 0.61642

0.31155 0.32749 0.63904

5.1% 2.3% 3.7%

Off-Peak

0.25723 0.14784 0.40507

0.27001 0.15128 0.42129

5.0% 2.3% 4.0%

Super-Off-Peak

0.23603 0.11620 0.35223

0.24751 0.11890 0.36641

4.9% 2.3% 4.0%

Basic Charge - \$/day

Single-Family Residence

0.031 0.000 0.031

0.031 0.000 0.031

0.0% 0.0%

Multi-Family Residence

0.024 0.000 0.024

0.031 0.000 0.031

29.2% 29.2%

Minimum Charge - \$/day

Single Family Residence

0.346 0.000 0.346

0.346 0.000 0.346

0.0% 0.0%

Multi-Family Residence

0.346 0.000 0.346

0.346 0.000 0.346

0.0% 0.0%

Minimum Charge (Medical Baseline) - \$/day

Single Family Residence

0.173 0.173

0.173 0.173

0.0% 0.0%

Multi-Family Residence

0.173 0.173

0.173 0.173

0.0% 0.0%

California Climate Credit

(71.00) 0.00 (71.00)

(71.00) 0.00 (71.00)

0.0% 0.0%

Baseline Credit - \$/kWh

(0.09444) 0.00000 (0.09444)

(0.10239) 0.00000 (0.10239)

8.4% 8.4%

California Alternate Rates for

Energy Discount - %

100% 100%

29% 29%

-71.1% -71.1%

Family Electric Rate Assistance Discount - %

100% 100%

18% 18%

-82.0% -82.0%

Smart Energy Program (SEP)

Energy Payment - \$/kWh

0.00000 0.00000

(0.07000) 0.00000 (0.07000)

Capacity Payment - \$/summer day

0.0000 0.0000

(0.328) 0.0000 (0.328)

TOU-D-T

Energy Charge - \$/kWh

Summer Season

Level I (up to 130% of Baseline) - On-Peak

0.25440 0.20976 0.46416

0.28053 0.23200 0.51253

10.3% 10.6% 10.4%

Level II (More than 130% of Baseline) - On-Peak

0.31241 0.20976 0.52217

0.34575 0.23200 0.57775

10.7% 10.6% 10.6%

Level I (up to 130% of Baseline) - Off-Peak

0.16745 0.19069 0.35814

0.17914 0.21091 0.39005

7.0% 10.6% 8.9%

Level II (More than 130% of Baseline) - Off-Peak

0.20349 0.19069 0.39418

0.21828 0.21091 0.42919

7.3% 10.6% 8.9%

Winter Season

Level I (up to 130% of Baseline) - On-Peak

0.17261 0.15794 0.33055

0.18055 0.15976 0.34031

4.6% 1.2% 3.0%

Level II (More than 130% of Baseline) - On-Peak

0.23062 0.15794 0.38856

0.24577 0.15976 0.40553

6.6% 1.2% 4.4%

Level I (up to 130% of Baseline) - Off-Peak

0.15855 0.14358 0.30213

0.16657 0.14523 0.31180

5.1% 1.1% 3.2%

Level II (More than 130% of Baseline) - Off-Peak

0.19459 0.14358 0.33817

0.20571 0.14523 0.35094

5.7% 1.1% 3.8%

Basic Charge - \$/day

Single-Family Residence

0.031 0.000 0.031

0.031 0.000 0.031

0.0% 0.0%

Multi-Family Residence

0.024 0.000 0.024

0.031 0.000 0.031

29.2% 29.2%

Minimum Charge - \$/day

Single Family Residence

0.346 0.000 0.346

0.346 0.000 0.346

0.0% 0.0%

Multi-Family Residence

0.346 0.000 0.346

0.346 0.000 0.346

0.0% 0.0%

Minimum Charge (Medical Baseline) - \$/day

Single Family Residence

0.173 0.173

0.173 0.173

0.0% 0.0%

Multi-Family Residence

0.173 0.173

0.173 0.173

0.0% 0.0%

California Climate Credit

(71.00) 0.00 (71.00)

(71.00) 0.00 (71.00)

0.0% 0.0%

Smart Energy Program (SEP)

Energy Payment - \$/kWh

0.00000 0.00000

(0.07000) 0.00000 (0.07000)

Capacity Payment - \$/summer day

(0.328) 0.0000 (0.328)

(0.328) 0.0000 (0.328)

0.2% 0.2%

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October 2023 Rates		
Delivery	Generation	Total Rate

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

Delivery Change	Generation Change	Total Rate Change

TOU-D-T-CPP

Energy Charge - \$/kWh									
Summer Season									
Level I (up to 130% of Baseline) - On-Peak		0.25440	0.20976	0.46416	0.28053	0.23200	0.51253	10.3%	10.6%
Level II (More than 130% of Baseline) - On-Peak		0.31241	0.20976	0.52217	0.34575	0.23200	0.57775	10.7%	10.6%
Level I (up to 130% of Baseline) - Off-Peak		0.16745	0.19069	0.35814	0.17914	0.21091	0.39005	7.0%	10.6%
Level II (More than 130% of Baseline) - Off-Peak		0.20349	0.19069	0.39418	0.21828	0.21091	0.42919	7.3%	10.6%
Winter Season									
Level I (up to 130% of Baseline) - On-Peak		0.17261	0.15794	0.33055	0.18055	0.15976	0.34031	4.6%	1.2%
Level II (More than 130% of Baseline) - On-Peak		0.23062	0.15794	0.38856	0.24577	0.15976	0.40553	6.6%	1.2%
Level I (up to 130% of Baseline) - Off-Peak		0.15855	0.14358	0.30213	0.16657	0.14523	0.31180	5.1%	1.1%
Level II (More than 130% of Baseline) - Off-Peak		0.19459	0.14358	0.33817	0.20571	0.14523	0.35094	5.7%	1.1%
Basic Charge - \$/day									
Single-Family Residence		0.031	0.000	0.031	0.031	0.000	0.031	0.0%	0.0%
Multi-Family Residence		0.024	0.000	0.024	0.031	0.000	0.031	29.2%	29.2%
Minimum Charge - \$/day									
Single Family Residence		0.346	0.000	0.346	0.346	0.000	0.346	0.0%	0.0%
Multi-Family Residence		0.346	0.000	0.346	0.346	0.000	0.346	0.0%	0.0%
Minimum Charge (Medical Baseline) - \$/day									
Single Family Residence		0.173		0.173	0.173		0.173	0.0%	0.0%
Multi-Family Residence		0.173		0.173	0.173		0.173	0.0%	0.0%
California Climate Credit		(71.00)	0.00	(71.00)	(71.00)	0.00	(71.00)	0.0%	0.0%
Smart Energy Program (SEP)									
Energy Payment - \$/kWh			0.00000	0.00000	(0.07000)	0.00000	(0.07000)		
Capacity Payment - \$/summer day		(0.328)	0.0000	(0.3275)	(0.328)	0.0000	(0.328)	0.2%	0.2%
CPP Event Energy Charge - \$/kWh			0.80000	0.80000		0.80000	0.80000		0.0%
Summer CPP Non-Event Credit									0.0%
Summer On-Peak Energy Credit - \$/kWh			-0.15170	(0.15170)		-0.15170	-0.15170		0.0%

TOU-EV-1

Energy Charge - \$/kWh									
Summer Season - On-Peak		0.37196	0.40124	0.77320	0.38746	0.36718	0.75464	4.2%	-8.5%
Off-Peak		0.10699	0.06133	0.16832	0.11809	0.06444	0.18253	10.4%	5.1%
Winter Season - On-Peak		0.24816	0.16927	0.41743	0.26433	0.27441	0.53874	6.5%	62.1%
Off-Peak		0.09821	0.07597	0.17418	0.10998	0.05223	0.16221	12.0%	-31.2%
Meter Charge - \$/month		3.39	0.00	3.39	2.52	0.00	2.52	-25.7%	-25.7%

GS-1

Energy Charge - \$/kWh									
Summer		0.13471	0.19996	0.33467	0.15326	0.14528	0.29854	13.8%	-27.3%
Winter		0.12778	0.13452	0.26230	0.09681	0.11130	0.20811	-24.2%	-17.3%
Customer Charge - \$/day		0.468		0.468	0.620		0.620	32.5%	32.5%
Three Phase Service - \$/day		0.046		0.046	0.268		0.268	482.6%	482.6%
Voltage Discount, Energy - \$/kWh									
From 2 kV to 50 kV		(0.00130)	(0.00180)	(0.00310)	(0.00166)	(0.00163)	(0.00329)	27.7%	-9.4%
From 51 kV to 219 kV		(0.02653)	(0.00393)	(0.03046)	(0.02934)	(0.00353)	(0.03287)	10.6%	-10.2%
220 kV and above		(0.08212)	(0.00398)	(0.08610)	(0.06651)	(0.00356)	(0.07007)	-19.0%	-10.6%
California Climate Credit - \$/kWh/Meter/Month		(71.00000)	0.00000	(71.00000)	(71.00000)	0.00000	(71.00000)	0.0%	0.0%

TOU-GS-1 (Rate E)

Energy Charge - \$/kWh									
Summer Season									
On-Peak		0.16367	0.59677	0.76044	0.23882	0.34126	0.58008	45.9%	-42.8%
Mid-peak		0.16367	0.15887	0.32254	0.16428	0.12342	0.28770	0.4%	-22.3%
Off-Peak		0.12575	0.11357	0.23932	0.13308	0.10289	0.23597	5.8%	-9.4%
Winter Season									
Mid-peak		0.16367	0.24112	0.40479	0.09937	0.18307	0.28244	-39.3%	-24.1%
Off-Peak		0.12575	0.13394	0.25969	0.09159	0.11114	0.20273	-27.2%	-17.0%
Super-Off-Peak		0.10800	0.07031	0.17831	0.10052	0.06863	0.16915	-6.9%	-2.4%
Customer Charge - \$/day		0.468	0.000	0.468	0.620	0.000	0.620	32.5%	32.5%
Three-Phase Service - \$/day		0.046	0.000	0.046	0.268	0.000	0.268	482.6%	482.6%
Voltage Discount, Energy - \$/kWh									
From 2 kV to 50 kV		(0.00130)	(0.00180)	(0.00310)	(0.00166)	(0.00163)	(0.00329)	27.7%	-9.4%
From 51 kV to 219 kV		(0.02653)	(0.00393)	(0.03046)	(0.02934)	(0.00353)	(0.03287)	10.6%	-10.2%
220 kV and above		(0.08212)	(0.00398)	(0.08610)	(0.06651)	(0.00356)	(0.07007)	-19.0%	-10.6%
California Climate Credit - \$/kWh/Meter/Month		(71.00)	-	(71.00)	(71.00)	-	(71.00)	0.0%	0.0%

			October 2023 Rates			Proposed 2025 GRC Rates					
			Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-GS-1 (Rate ES)											
Energy Charge - \$/kWh											
Summer Season											
On-Peak			0.26227	0.64467	0.90694	0.22032	0.34126	0.56158	-16.0%	-47.1%	-38.1%
Mid-peak			0.17545	0.17181	0.34726	0.14579	0.12342	0.26921	-16.9%	-28.2%	-22.5%
Off-Peak			0.13057	0.12271	0.25328	0.11458	0.10289	0.21747	-12.2%	-16.2%	-14.1%
Winter Season											
Mid-peak			0.09436	0.22507	0.31943	0.08088	0.18307	0.26395	-14.3%	-18.7%	-17.4%
Off-Peak			0.08566	0.12515	0.21081	0.07309	0.11114	0.18423	-14.7%	-11.2%	-12.6%
Super-Off-Peak			0.09170	0.06556	0.15726	0.08202	0.06863	0.15065	-10.6%	4.7%	-4.2%
Customer Charge - \$/day			0.982	0.000	0.982	1.302	0.000	1.302	32.6%		32.6%
Three-Phase Service - \$/day			0.046	0.000	0.046	0.268	0.000	0.268	482.6%		482.6%
Voltage Discount, Energy - \$/kWh											
From 2 kV to 50 kV			(0.00130)	(0.00180)	(0.00310)	(0.00166)	(0.00163)	(0.00329)	27.7%	-9.4%	6.1%
From 51 kV to 219 kV			(0.02653)	(0.00393)	(0.03046)	(0.02934)	(0.00353)	(0.03287)	10.6%	-10.2%	7.9%
220 kV and above			(0.08212)	(0.00398)	(0.08610)	(0.06651)	(0.00356)	(0.07007)	-19.0%	-10.6%	-18.6%
California Climate Credit - \$/kWh/Meter/Month			(71.00)	-	(71.00)	(71.00)	-	(71.00)	0.0%		0.0%
TOU-GS-1 (Rate D)											
Energy Charge - \$/kWh											
Summer Season											
On-Peak			0.06243	0.16002	0.22245	0.05970	0.14295	0.20265	-4.4%	-10.7%	-8.9%
Mid-peak			0.06243	0.14449	0.20692	0.05970	0.12105	0.18075	-4.4%	-16.2%	-12.6%
Off-Peak			0.04373	0.09470	0.13843	0.04500	0.10166	0.14666	2.9%	7.3%	5.9%
Winter Season											
Mid-peak			0.06243	0.15064	0.21307	0.05970	0.12965	0.18935	-4.4%	-13.9%	-11.1%
Off-Peak			0.04373	0.10635	0.15008	0.04500	0.09655	0.14155	2.9%	-9.2%	-5.7%
Super-Off-Peak			0.03530	0.07956	0.11486	0.03950	0.07714	0.11664	11.9%	-3.0%	1.5%
Customer Charge - \$/day			0.468	0.000	0.468	0.620	0.000	0.620	32.5%		32.5%
Facilities Related Demand Charge - \$/kW			16.49	0.00	16.49	13.85	0.00	13.85	-16.0%		-16.0%
Time Related Demand Charge - \$/kW											
Summer Season											
On-Peak			3.75	22.54	26.29	2.95	8.87	11.82	-21.3%	-60.6%	-55.0%
Mid-peak			0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season											
Mid-peak			0.00	6.92	6.92	0.00	3.39	3.39		-51.0%	-51.0%
Three-Phase Service - \$/day			0.046	0.000	0.046	0.268	0.000	0.268	482.6%		482.6%
Voltage Discount, Energy - \$/kWh											
From 2 kV to 50 kV			0.00000	(0.00064)	(0.00064)	(0.00052)	(0.00111)	(0.00163)		73.4%	154.7%
From 51 kV to 219 kV			0.00000	(0.00125)	(0.00125)	(0.00640)	(0.00215)	(0.00855)		72.0%	584.0%
220 kV and above			(0.01819)	(0.00129)	(0.01948)	(0.01189)	(0.00108)	(0.01297)	-34.6%	-16.3%	-33.4%
Voltage Discount, Facilities Related Demand - \$/kW											
From 2 kV to 50 kV			(0.26)	0.00	(0.26)	(0.21)	0.00	(0.21)	-19.2%		-19.2%
From 51 kV to 219 kV			(5.71)	0.00	(5.71)	(4.42)	0.00	(4.42)	-22.6%		-22.6%
220 kV and above			(12.99)	0.00	(12.99)	(10.35)	0.00	(10.35)	-20.3%		-20.3%
Voltage Discount, Time-Related Demand - \$/kW											
Summer											
From 2 kV to 50 kV			(0.08)	(0.20)	(0.28)	(0.07)	(0.20)	(0.27)	-12.5%	0.0%	-3.6%
From 51 kV to 219 kV			(1.42)	(0.47)	(1.89)	(1.01)	(0.46)	(1.47)	-28.9%	-2.1%	-22.2%
220 kV and above			(1.42)	(0.47)	(1.89)	(2.95)	(0.47)	(3.42)	107.7%	0.0%	81.0%
Winter											
From 2 kV to 50 kV						0.00	(0.08)	(0.08)			
From 51 kV to 219 kV						0.00	(0.17)	(0.17)			
220 kV and above						0.00	(0.17)	(0.17)			
California Alternate Rates for Energy Discount—%			1.00			0.29		0.29	-71.1%		
California Climate Credit - \$/kWh/Meter/Month			(71.00000)	0.00000	(71.00000)	(71.00000)	0.00000	(71.00000)	0.0%		0.0%

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October 2023 Rates		
Delivery	Generation	Total Rate

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

Delivery Change	Generation Change	Total Rate Change

TOU-GS-1 (RateLG)

Energy Charge - \$/kWh

Summer Season

On-Peak

0.14325

0.59677

0.74002

0.12068

0.34126

0.46194

-15.8%

-42.8%

-37.6%

Mid-peak

0.14325

0.15887

0.30212

0.12068

0.12342

0.24410

-15.8%

-22.3%

-19.2%

Off-Peak

0.07604

0.11357

0.18961

0.07139

0.10289

0.17428

-6.1%

-9.4%

-8.1%

Winter Season

Mid-peak

0.14325

0.24112

0.38437

0.12068

0.18307

0.30375

-15.8%

-24.1%

-21.0%

Off-Peak

0.07604

0.13394

0.20998

0.07139

0.11114

0.18253

-6.1%

-17.0%

-13.1%

Super-Off-Peak

0.04572

0.07031

0.11603

0.05296

0.06863

0.12159

15.8%

-2.4%

4.8%

Customer Charge - \$/day

0.468

0.000

0.468

0.620

0.000

0.620

32.5%

32.5%

Facilities Related Demand Charge - \$/kW

9.60

0.00

9.60

8.31

0.00

8.31

-13.4%

-13.4%

Time Related Demand Charge - \$/kW

Summer Season

On-Peak

0.00

0.00

0.00

0.00

0.00

Mid-peak

0.00

0.00

0.00

0.00

0.00

Three-Phase Service - \$/day

0.046

0.000

0.046

0.268

0.000

0.268

482.6%

482.6%

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV

-0.00077

(0.00180)

(0.00257)

-0.00118

(0.00163)

(0.00281)

53.2%

-9.4%

9.3%

From 51 kV to 219 kV

-0.01651

(0.00393)

(0.02044)

-0.01939

(0.00353)

(0.02292)

17.4%

-10.2%

12.1%

220 kV and above

-0.05310

(0.00398)

(0.05708)

-0.04319

(0.00356)

(0.04675)

-18.7%

-10.6%

-18.1%

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV

(0.12)

0.00

(0.12)

(0.10)

0.00

(0.10)

-16.7%

-16.7%

From 51 kV to 219 kV

(2.68)

0.00

(2.68)

(2.05)

0.00

(2.05)

-23.5%

-23.5%

220 kV and above

(6.10)

0.00

(6.10)

(4.81)

0.00

(4.81)

-21.1%

-21.1%

Voltage Discount, Time Related Demand - \$/kW

From 2 kV to 50 kV

0.00

0.00

0.00

0.00

0.00

From 51 kV to 219 kV

0.00

0.00

0.00

0.00

0.00

220 kV and above

0.00

0.00

0.00

0.00

0.00

California Climate Credit - \$/kWh/Meter/Month

(71.00000)

0.00000

(71.00000)

(71.00000)

0.00000

(71.00000)

0.0%

0.0%

TOU-GS-1-CPP

Energy Charge - \$/kWh

Summer Season

On-Peak

0.16367

0.59677

0.76044

0.23882

0.34126

0.58008

45.9%

-42.8%

-23.7%

Mid-peak

0.16367

0.15887

0.32254

0.16428

0.12342

0.28770

0.4%

-22.3%

-10.8%

Off-Peak

0.12575

0.11357

0.23932

0.13308

0.10289

0.23597

5.8%

-9.4%

-1.4%

Winter Season

Mid-peak

0.16367

0.24112

0.40479

0.09937

0.18307

0.28244

-39.3%

-24.1%

-30.2%

Off-Peak

0.12575

0.13394

0.25969

0.09159

0.11114

0.20273

-27.2%

-17.0%

-21.9%

Super-Off-Peak

0.10800

0.07031

0.17831

0.10052

0.06863

0.16915

-6.9%

-2.4%

-5.1%

Customer Charge - \$/day

0.468

0.000

0.468

0.620

0.000

0.620

32.5%

32.5%

Three-Phase Service - \$/day

0.046

0.000

0.046

0.268

0.000

0.268

482.6%

482.6%

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV

(0.00130)

(0.00180)

(0.00310)

(0.00166)

(0.00163)

(0.00329)

--

TOU-GS-1-D-RTP

Energy Charge - \$/kWh

Summer Season

On-Peak

Mid-Peak

Off-Peak

Winter Season

Mid-Peak

Off-Peak

Suepr-Off-Peak

Customer Charge - \$/day

Facilities Related Demand Charge - \$/kW

Time Related Demand Charge - \$/kW

Summer Season

On-Peak

Mid-Peak

Three-Phase Service - \$/day

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV

Above 50 kV but below 220 kV

At 220 kV

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV

From 51 kV to 219 kV

220 kV and above

Voltage Discount, Time Related Demand - \$/kW

Summer

From 2 kV to 50 kV

From 51 kV to 219 kV

220 kV and above

Winter

From 2 kV to 50 kV

From 51 kV to 219 kV

220 kV and above

~~Energy Discount -%~~

~~California Alternate Rates for~~

California Climate Credit - \$/kWh/Meter/Month

October 2023 Rates		
Delivery	Generation	Total Rate

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

Delivery Change	Generation Change	Total Rate Change
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0.06243 Variable* Variable*

0.06243 Variable* Variable*

0.04373 Variable* Variable*

0.06243 Variable* Variable*

0.04373 Variable* Variable*

0.03530 Variable* Variable*

0.468

0.468

16.49

16.49

3.75

0.00

0.00

0.00

0.046

0.046

0.00000 (0.00180) (0.00180)

0.00000 (0.00393) (0.00393)

(0.01819) (0.00398) (0.02217)

(0.26) (0.26)

(5.71) (5.71)

(12.99) (12.99)

(0.08) 0.00 (0.08)

(1.42) 0.00 (1.42)

(1.42) 0.00 (1.42)

~~1.00~~

(71.00000) 0.00000 (71.00000)

0.05970 Variable* Variable*

0.05970 Variable* Variable*

0.04500 Variable* Variable*

0.05970 Variable* Variable*

0.04500 Variable* Variable*

0.03950 Variable* Variable*

0.620

0.620

13.85

13.85

2.95

0.00

0.00

0.00

0.268

0.268

(0.00052) (0.00163) (0.00215)

(0.00640) (0.00353) (0.00993)

(0.01189) (0.00356) (0.01545)

(0.21) (0.21)

(4.42) (4.42)

(10.35) (10.35)

(0.07) 0.00 (0.07)

(1.01) 0.00 (1.01)

(2.95) 0.00 (2.95)

~~0.29~~

~~0.29~~

(71.00000) 0.00000 (71.00000)

-4.4%

-4.4%

2.9%

-4.4%

2.9%

11.9%

32.5%

32.5%

-16.0%

-16.0%

-21.3%

-21.3%

482.6%

482.6%

-9.4%

19.4%

-10.2%

152.7%

-34.6%

-10.6%

-30.3%

-19.2%

-19.2%

-22.6%

-22.6%

-20.3%

-20.3%

-12.5%

-12.5%

-28.9%

-28.9%

107.7%

107.7%

-71.1%

0.0%

0.0%

TOU-EV-7 (Rate E)

Energy Charge - \$/kWh

Summer Season On-Peak

Mid-Peak

Off-Peak

Winter Season On-Peak

Mid-Peak

Off-Peak

Customer Charge - \$/day

EV Submeter Credit - \$/Meter/Day

Three-Phase Service - \$/day

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV

51 kV to 219 kV

220 kV and above

California Climate Credit - \$/kWh/Meter/Month

0.22904 0.44758 0.67662

0.22904 0.15887 0.38791

0.12539 0.13054 0.25593

0.22904 0.24112 0.47016

0.12539 0.15359 0.27898

0.07690 0.07031 0.14721

0.237

0.237

(0.091) (0.091)

0.046

0.046

(0.00130) (0.00180) (0.00310)

(0.02653) (0.00393) (0.03046)

(0.08212) (0.00398) (0.08610)

(71.00) (71.00)

0.27957 0.34126 0.62083

0.18187 0.12342 0.30529

0.13757 0.10289 0.24046

0.09350 0.18307 0.27657

0.08176 0.11114 0.19290

0.09497 0.06863 0.16360

0.620

0.620

(0.084) (0.084)

0.268

0.268

(0.00166) (0.00163) (0.00329)

(0.02934) (0.00353) (0.03287)

(0.06651) (0.00356) (0.07007)

(71.00) (71.00)

22.1%

-23.8%

-8.2%

-20.6%

-22.3%

-21.3%

9.7%

-21.2%

-6.0%

-59.2%

-24.1%

-41.2%

-34.8%

-27.6%

-30.9%

23.5%

-2.4%

11.1%

161.6%

161.6%

7.7%

7.7%

482.6%

482.6%

27.7%

-9.4%

6.1%

10.6%

-10.2%

7.9%

-19.0%

-10.6%

-18.6%

0.0%

0.0%

TOU-EV-7 (Rate D)

Energy Charge - \$/kWh

Summer Season On-Peak

Mid-Peak

Off-Peak

Winter Season On-Peak

Mid-Peak

Off-Peak

Customer Charge - \$/day

EV Submeter Credit - \$/Meter/Day

Three-Phase Service - \$/day

Facilities Related Demand Charge - \$/kW

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV

51 kV to 219 kV

220 kV and above

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV

0.22904 0.44758 0.67662

0.22904 0.15887 0.38791

0.12539 0.13054 0.25593

0.22904 0.24112 0.47016

0.12539 0.15359 0.27898

0.07690 0.07031 0.14721

0.237

0.237

-0.091 (0.091)

0.046

0.046

0.00 0.000

(0.00130) (0.00180) (0.00310)

(0.02653) (0.00393) (0.03046)

(0.08212) (0.00398) (0.08610)

0.00

0.27618 0.34126 0.61744

0.17848 0.12342 0.30190

0.13417 0.10289 0.23706

0.09011 0.18307 0.27318

0.07837 0.11114 0.18951

0.09158 0.06863 0.16021

0.620

0.620

-0.084 (0.084)

0.268

0.268

0.70 0.70

(0.00166) (0.00163) (0.00329)

(0.02934) (0.00353) (0.03287)

(0.06651) (0.00356) (0.07007)

0.00

0.00

--

51 kV to 219 kV
 220 kV and above
 California Climate Credit - \$/kWh/Meter/Month

October 2023 Rates		
Delivery	Generation	Total Rate

0.00
 0.00
 (71.00) (71.00)

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

0.00
 0.00
 (71.00) (71.00)

Delivery Change	Generation Change	Total Rate Change
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0.0% 0.0%

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October 2023 Rates		
Delivery	Generation	Total Rate

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

Delivery Change	Generation Change	Total Rate Change

TOU-GS-1 (Rate A) - GF

Energy Charge - \$/kWh

Summer Season

On-Peak

Mid-peak

Off-Peak

Winter Season

Mid-peak

Off-Peak

Customer Charge - \$/day

Three-Phase Service - \$/day

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV

From 51 kV to 219 kV

220 kV and above

California Climate Credit - \$/kWh/Meter/Month

TOU-GS-1 (Rate B) - GF

Energy Charge - \$/kWh

Summer Season

On-Peak

Mid-peak

Off-Peak

Winter Season

Mid-peak

Off-Peak

Customer Charge - \$/day

Facilities Related Demand Charge - \$/kW

Time Related Demand Charge - \$/kW

Summer Season

On-Peak

Mid-peak

Three-Phase Service - \$/day

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV

From 51 kV to 219 kV

220 kV and above

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV

From 51 kV to 219 kV

220 kV and above

Voltage Discount, Time-Related Demand - \$/kW

From 2 kV to 50 kV

From 51 kV to 219 kV

220 kV and above

California Climate Credit - \$/kWh/Meter/Month

TOU-GS-1 (Rate C) - GF

Energy Charge - \$/kWh

Summer Season

On-Peak

Mid-peak

Off-Peak

Winter Season

Mid-peak

Off-Peak

Customer Charge - \$/day

Facilities Related Demand Charge - \$/kW

Three-Phase Service - \$/day

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV

From 51 kV to 219 kV

220 kV and above

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV

From 51 kV to 219 kV

220 kV and above

California Climate Credit - \$/kWh/Meter/Month

			October 2023 Rates			Proposed 2025 GRC Rates					
			Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
GS-2 (Non TOU Rate)											
Energy Charge - \$/kWh	Summer		0.08617	0.10432	0.19049	0.07825	0.10919	0.18744	-9.2%	4.7%	-1.6%
	Winter		0.05157	0.10807	0.15964	0.05425	0.11148	0.16573	5.2%	3.2%	3.8%
Customer Charge - \$/month			188.98		188.98	140.00		140.00	-25.9%		-25.9%
Facilities Related Demand Charge - \$/kW			21.21		21.21	19.42		19.42	-8.4%		-8.4%
Summer Time Related Demand Charge - \$/kW			0.00	25.30	25.30	0.00	10.38	10.38		-59.0%	-59.0%
Single Phase Service - \$/month			(6.55)	0.00	(6.55)	(105.60)	0.00	(105.60)	1512.2%		1512.2%
Voltage Discount, Facilities Related Demand - \$/kW											
From 2 kV to 50 kV			(0.33)		(0.33)	(0.30)		(0.30)	-9.1%		-9.1%
From 51 kV to 219 kV			(7.21)		(7.21)	(6.24)		(6.24)	-13.5%		-13.5%
220 kV and above			(16.41)		(16.41)	(14.62)		(14.62)	-10.9%		-10.9%
Voltage Discount, Time-Related Demand - \$/kW											
From 2 kV to 50 kV			0.00	(0.58)	(0.58)	0.00	(0.23)	(0.23)		-60.3%	-60.3%
From 51 kV to 219 kV			0.00	(1.33)	(1.33)	0.00	(0.53)	(0.53)		-60.2%	-60.2%
220 kV and above			0.00	(1.34)	(1.34)	0.00	(0.54)	(0.54)		-59.7%	-59.7%
Voltage Discount, Energy - \$/kWh											
From 2 kV to 50 kV			(0.00064)	(0.00149)	(0.00213)	(0.00072)	(0.00146)	(0.00218)	12.5%	-2.0%	2.3%
From 51 kV to 219 kV			(0.01213)	(0.00326)	(0.01539)	(0.01005)	(0.00316)	(0.01321)	-17.1%	-3.1%	-14.2%
220 kV and above			(0.03218)	(0.00329)	(0.03547)	(0.02937)	(0.00319)	(0.03256)	-8.7%	-3.0%	-8.2%
Bill Limiter (GS-1 to GS-2) - %			20.89%	79.11%	100.00%	20.89%	79.11%	100.00%	0.0%	0.0%	0.0%
California Climate Credit - \$/kWh/Meter/Month			(71.00)	-	(71.00)	(71.00)	-	(71.00)	0.0%		0.0%
GS-2 (TOU Rate D)											
Energy Charge - \$/kWh	Summer Season										
	On-Peak		0.04637	0.15394	0.20031	0.04701	0.14478	0.19179	1.4%	-6.0%	-4.3%
	Mid-peak		0.04508	0.14035	0.18543	0.04583	0.12146	0.16729	1.7%	-13.5%	-9.8%
	Off-Peak		0.04479	0.09005	0.13484	0.04556	0.10014	0.14570	1.7%	11.2%	8.1%
	Winter Season										
	Mid-peak		0.04637	0.10391	0.15028	0.04701	0.11535	0.16236	1.4%	11.0%	8.0%
	Off-Peak		0.04508	0.10454	0.14962	0.04583	0.11114	0.15697	1.7%	6.3%	4.9%
	Super-Off-Peak		0.04433	0.05488	0.09921	0.04516	0.06863	0.11379	1.9%	25.1%	14.7%
Customer Charge - \$/month			188.98		188.98	140.00		140.00	-25.9%		-25.9%
Facilities Related Demand Charge - \$/kW			21.21		21.21	19.42		19.42	-8.4%		-8.4%
Time Related Demand Charge - \$/kW											
	Summer Season										
	On-Peak		13.57	28.57	42.14	10.17	11.96	22.13	-25.1%	-58.1%	-47.5%
	Mid-Peak		0.00	0.00	0.00	0.00	0.00	0.00			
	Winter Season										
	Mid-Peak		2.20	7.50	9.70	2.65	4.73	7.38	20.5%	-36.9%	-23.9%
Single Phase Service - \$/month			(6.55)	0.00	(6.55)	(105.60)	0.00	(105.60)	1512.2%		1512.2%
Voltage Discount, Facilities Related Demand - \$/kW											
From 2 kV to 50 kV			(0.33)		(0.33)	(0.30)		(0.30)	-9.1%		-9.1%
From 51 kV to 219 kV			(7.21)		(7.21)	(6.24)		(6.24)	-13.5%		-13.5%
220 kV and above			(16.41)		(16.41)	(14.62)		(14.62)	-10.9%		-10.9%
Voltage Discount, Time-Related Demand - \$/kW											
	Summer Season										
	From 2 kV to 50 kV		(0.27)	(0.65)	(0.92)	(0.25)	(0.27)	(0.52)	-7.4%	-58.5%	-43.5%
	From 51 kV to 219 kV		(5.12)	(1.50)	(6.62)	(3.48)	(0.62)	(4.10)	-32.0%	-58.7%	-38.1%
	220 kV and above		(13.57)	(1.51)	(15.08)	(10.17)	(0.63)	(10.80)	-25.1%	-58.3%	-28.4%
	Winter Season										
	From 2 kV to 50 kV		(0.27)	(0.65)	(0.92)	(0.07)	(0.11)	(0.18)	-74.1%	-83.1%	-80.4%
	From 51 kV to 219 kV		(5.12)	(1.50)	(6.62)	(0.91)	(0.24)	(1.15)	-82.2%	-84.0%	-82.6%
	220 kV and above		(13.57)	(1.51)	(15.08)	(2.65)	(0.24)	(2.89)	-80.5%	-84.1%	-80.8%
Voltage Discount, Energy - \$/kWh											
From 2 kV to 50 kV			(0.00027)	(0.00128)	(0.00155)	(0.00029)	(0.00132)	(0.00161)	7.4%	3.1%	3.9%
From 51 kV to 219 kV			(0.00493)	(0.00280)	(0.00773)	(0.00405)	(0.00286)	(0.00691)	-17.8%	2.1%	-10.6%
220 kV and above			(0.01309)	(0.00282)	(0.01591)	(0.01188)	(0.00289)	(0.01477)	-9.2%	2.5%	-7.2%
TOU Rate Meter Charge - \$/month											
TOU-RTEM			28.72	0.00	28.72	28.72	0.00	28.72	0.0%		0.0%
California Climate Credit - \$/kWh/Meter/Month			(71.00000)	0.00000	(71.00000)	(71.00000)	0.00000	(71.00000)	0.0%		0.0%

--

GS-2 (TOU Rate E)

Energy Charge - \$/kWh

Summer Season

On-Peak

Mid-peak

Off-Peak

Winter Season

Mid-peak

Off-Peak

Customer Charge - \$/month

Facilities Related Demand Charge - \$/kW

Time Related Demand Charge - \$/kW

Summer Season

On-Peak

Mid-Peak

Winter Season

Mid-Peak

Single Phase Service - \$/month

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV

From 51 kV to 219 kV

220 kV and above

Voltage Discount, Time Related Demand - \$/kW

Summer Season

From 2 kV to 50 kV

From 51 kV to 219 kV

220 kV and above

Winter Season

From 2 kV to 50 kV

From 51 kV to 219 kV

220 kV and above

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV

From 51 kV to 219 kV

220 kV and above

TOU Rate Meter Charge - \$/month

TOU-RTEM

California Climate Credit - \$/kWh/Meter/Month

October 2023 Rates		
Delivery	Generation	Total Rate

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

Delivery Change	Generation Change	Total Rate Change
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0.35062 0.51705 0.86767

0.20029 0.14035 0.34064

0.12104 0.09005 0.21109

0.05953 0.16149 0.22102

0.04384 0.10454 0.14838

0.05496 0.05488 0.10984

188.98 188.98

12.50 0.00 12.50

0.00 8.03 8.03

0.00 0.00 0.00

0.00 3.11 3.11

(6.55) 0.00 (6.55)

(0.15) 0.00 (0.15)

(3.38) 0.00 (3.38)

(7.70) 0.00 (7.70)

0.00 (0.27) (0.27)

0.00 (0.62) (0.62)

0.00 (0.63) (0.63)

0.00 (0.27) (0.27)

0.00 (0.62) (0.62)

0.00 (0.63) (0.63)

(0.00125) (0.00190) (0.00315)

(0.02544) (0.00422) (0.02966)

(0.06252) (0.00425) (0.06677)

28.72 0.00 28.72

(71.00) - (71.00)

0.27949 0.29663 0.57612

0.16629 0.12146 0.28775

0.10942 0.10014 0.20956

0.06032 0.16414 0.22446

0.04643 0.11114 0.15757

0.06151 0.06863 0.13014

140.00 140.00

11.59 0.00 11.59

0.00 3.19 3.19

0.00 0.00 0.00

0.00 1.13 1.13

(105.60) 0.00 (105.60)

(0.14) 0.00 (0.14)

(2.90) 0.00 (2.90)

(6.79) 0.00 (6.79)

0.00 (0.07) (0.07)

0.00 (0.17) (0.17)

0.00 (0.17) (0.17)

0.00 (0.03) (0.03)

0.00 (0.06) (0.06)

0.00 (0.06) (0.06)

(0.00125) (0.00170) (0.00295)

(0.02115) (0.00372) (0.02487)

(0.05511) (0.00376) (0.05887)

28.72 0.00 28.72

(71.00) - (71.00)

-20.3% -42.6% -33.6%

-17.0% -13.5% -15.5%

-9.6% 11.2% -0.7%

1.3% 1.6% 1.6%

5.9% 6.3% 6.2%

11.9% 25.1% 18.5%

-25.9% -25.9%

-7.3% -7.3%

-60.3% -60.3%

0.00 0.00 0.00

-63.7% -63.7%

1512.2% 1512.2%

-6.7% -6.7%

-14.2% -14.2%

-11.8% -11.8%

-74.1% -74.1%

-72.6% -72.6%

-73.0% -73.0%

-88.9% -88.9%

-90.3% -90.3%

-90.5% -90.5%

0.0% -10.5% -6.3%

-16.9% -11.8% -16.1%

-11.9% -11.5% -11.8%

0.0% 0.0%

0.0% 0.0%

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October 2023 Rates		
Delivery	Generation	Total Rate

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

Delivery Change	Generation Change	Total Rate Change

TOU-GS-2-CPP

Energy Charge - \$/kWh

Summer Season

On-Peak
Mid-peak
Off-Peak

Winter Season

Mid-peak
Off-Peak
Super-Off-Peak

Customer Charge - \$/month

Single Phase Service - \$/month

Facilities Related Demand Charge - \$/kW

Time Related Demand Charge - \$/kW

Summer Season

On-Peak
Mid-Peak

Winter Season

Mid-Peak

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV
Above 50 kV but below 220 kV
At 220 kV

Voltage Discount, Time-Related Demand - \$/kW

Summer Season

From 2 kV to 50 kV
Above 50 kV but below 220 kV
At 220 kV

Winter Season

From 2 kV to 50 kV
Above 50 kV but below 220 kV
At 220 kV

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV
Above 50 kV but below 220 kV
At 220 kV

TOU Rate Meter Charge - \$/month

TOU-RTEM

CPP Event Energy Charge - \$/kWh

Summer CPP Non-Event Credit

On-Peak Demand Credit - \$/kW

California Climate Credit - \$/kWh/Meter/Month

0.04637 0.15394 0.20031
0.04508 0.14035 0.18543
0.04479 0.09005 0.13484

0.04637 0.10391 0.15028
0.04508 0.10454 0.14962
0.04433 0.05488 0.09921

188.98 188.98

(6.55) (6.55)

21.21 0.00 21.21

13.57 28.57 42.14
0.00 0.00 0.00

2.20 7.50 9.70

(0.33) 0.00 (0.33)
(7.21) 0.00 (7.21)
(16.41) 0.00 (16.41)

(0.27) (0.65) (0.92)
(5.12) (1.50) (6.62)
(13.57) (1.51) (15.08)

(0.27) (0.65) (0.92)
(5.12) (1.50) (6.62)
(13.57) (1.51) (15.08)

(0.00027) (0.00128) (0.00155)
(0.00493) (0.00280) (0.00773)
(0.01309) (0.00282) (0.01591)

28.72 0.00 28.72

0.00000 0.80000 0.80000

0.00 (6.85) (6.85)

(71.00) - (71.00)

0.04701 0.14478 0.19179
0.04583 0.12146 0.16729
0.04556 0.10014 0.14570

0.04701 0.11535 0.16236
0.04583 0.11114 0.15697
0.04516 0.06863 0.11379

140.00 140.00

(105.60) (105.60)

19.42 0.00 19.42

10.17 11.96 22.13
0.00 0.00 0.00

2.65 4.73 7.38

(0.30) 0.00 (0.30)
(6.24) 0.00 (6.24)
(14.62) 0.00 (14.62)

(0.25) (0.27) (0.52)
(3.48) (0.62) (4.10)
(10.17) (0.63) (10.80)

(0.07) (0.11) (0.18)
(0.91) (0.24) (1.15)
(2.65) (0.24) (2.89)

(0.00029) (0.00132) (0.00161)
(0.00405) (0.00286) (0.00691)
(0.01188) (0.00289) (0.01477)

28.72 0.00 28.72

0.00000 0.80000 0.80000

0.00 (6.85) (6.85)

(71.00) - (71.00)

1.4% -6.0% -4.3%
1.7% -13.5% -9.8%
1.7% 11.2% 8.1%

1.4% 11.0% 8.0%
1.7% 6.3% 4.9%
1.9% 25.1% 14.7%

-25.9% -25.9%

1512.2% 1512.2%

-8.4% -8.4%

-25.1% -58.1% -47.5%
0.00 0.00 0.00

20.5% -36.9% -23.9%

-9.1% -9.1%
-13.5% -13.5%
-10.9% -10.9%

-7.4% -58.5% -43.5%
-32.0% -58.7% -38.1%
-25.1% -58.3% -28.4%

-74.1% -83.1% -80.4%
-82.2% -84.0% -82.6%
-80.5% -84.1% -80.8%

7.4% 3.1% 3.9%
-17.8% 2.1% -10.6%
-9.2% 2.5% -7.2%

0.0% 0.0%

0.0% 0.0%

0.0% 0.0%

0.0% 0.0%

--

TOU-GS-2-RTP

Energy Charge - \$/kWh

Summer Season

On-Peak

0.04637 Variable*

Variable*

0.04701 Variable*

Variable*

1.4%

Mid-Peak

0.04508 Variable*

Variable*

0.04583 Variable*

Variable*

1.7%

Off-Peak

0.04479 Variable*

Variable*

0.04556 Variable*

Variable*

1.7%

Winter Season

Mid-Peak

0.04637 Variable*

Variable*

0.04701 Variable*

Variable*

1.4%

Off-Peak

0.04508 Variable*

Variable*

0.04583 Variable*

Variable*

1.7%

Super-Off-Peak

0.04433 Variable*

Variable*

0.04516 Variable*

Variable*

1.9%

Customer Charge - \$/month

188.98

188.98

140.00

140.00

-25.9%

-25.9%

Single Phase Service - \$/month

(6.55)

(6.55)

(105.60)

(105.60)

1512.2%

1512.2%

Facilities Related Demand Charge - \$/kW

21.21

21.21

19.42

19.42

-8.4%

-8.4%

Time Related Demand Charge - \$/kW

Summer Season

On-Peak

13.57

0.00

13.57

10.17

0.00

10.17

-25.1%

-25.1%

Mid-Peak

0.00

0.00

0.00

0.00

0.00

0.00

Winter Season

Mid-Peak

2.20

0.00

2.20

2.65

0.00

2.65

20.5%

20.5%

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV

(0.33)

(0.33)

(0.30)

(0.30)

-9.1%

-9.1%

Above 50 kV but below 220 kV

(7.21)

(7.21)

(6.24)

(6.24)

-13.5%

-13.5%

At 220 kV

(16.41)

(16.41)

(14.62)

(14.62)

-10.9%

-10.9%

Voltage Discount, Time-Related Demand - \$/kW

Summer Season

From 2 kV to 50 kV

(0.27)

(0.27)

(0.25)

(0.25)

-7.4%

-7.4%

Above 50 kV but below 220 kV

(5.12)

(5.12)

(3.48)

(3.48)

-32.0%

-32.0%

At 220 kV

(13.57)

(13.57)

(10.17)

(10.17)

-25.1%

-25.1%

Winter Season

From 2 kV to 50 kV

(0.27)

(0.27)

(0.07)

(0.07)

-74.1%

-74.1%

Above 50 kV but below 220 kV

(5.12)

(5.12)

(0.91)

(0.91)

-82.2%

-82.2%

At 220 kV

(13.57)

(13.57)

(2.65)

(2.65)

-80.5%

-80.5%

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV

(0.00027)

(0.00190)

(0.00217)

(0.00029)

(0.00170)

(0.00199)

7.4%

-10.5%

-8.3%

Above 50 kV but below 220 kV

(0.00493)

(0.00422)

(0.00915)

(0.00405)

(0.00372)

(0.00777)

-17.8%

-11.8%

-15.1%

At 220 kV

(0.01309)

(0.00425)

(0.01734)

(0.01188)

(0.00376)

(0.01564)

-9.2%

-11.5%

-9.8%

TOU Rate Meter Charge - \$/month

TOU-RTEM

28.72

28.72

28.72

28.72

0.0%

0.0%

California Climate Credit - \$/kWh/Meter/Month

(71.00)

-

(71.00)

(71.00)

-

(71.00)

0.0%

0.0%

GS-2 (TOU Rate B) - GF

Energy Charge - \$/kWh

Summer Season

On-Peak

0.03199

0.11141

0.14340

0.03395

0.11654

0.15049

6.1%

4.6%

4.9%

Mid-Peak

0.03199

0.10422

0.13621

0.03395

0.10906

0.14301

6.1%

4.6%

5.0%

Off-Peak

0.03199

0.10027

0.13226

0.03395

0.10488

0.13883

6.1%

4.6%

5.0%

Winter Season

Mid-Peak

0.03199

0.13536

0.16735

0.03395

0.13056

0.16451

6.1%

-3.5%

-1.7%

Off-Peak

0.03199

0.07997

0.11196

0.03395

0.09025

0.12420

6.1%

12.9%

10.9%

Customer Charge - \$/month

188.98

188.98

140.00

140.00

-25.9%

-25.9%

Facilities Related Demand Charge - \$/kW

30.46

30.46

27.45

27.45

-9.9%

-9.9%

Time Related Demand Charge - \$/kW

Summer Season

On-Peak

0.00

19.81

19.81

0.00

8.19

8.19

-58.7%

-58.7%

Mid-Peak

0.00

6.66

6.66

0.00

2.74

2.74

-58.9%

-58.9%

Single Phase Service - \$/month

(6.55)

0.00

(6.55)

(105.60)

0.00

(105.60)

1512.2%

1512.2%

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV

(0.64)

(0.64)

(0.59)

(0.59)

-7.8%

-7.8%

From 51 kV to 219 kV

(12.94)

(12.94)

(10.31)

(10.31)

-20.3%

-20.3%

220 kV and above

(25.66)

(25.66)

(22.65)

(22.65)

-11.7%

-11.7%

Voltage Discount, Time-Related Demand - \$/kW

--

California Climate Credit - \$/kWh/Meter/Month

October 2023 Rates		
Delivery	Generation	Total Rate

(71.00000) 0.00000 (71.00000)

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

(71.00000) 0.00000 (71.00000)

Delivery Change	Generation Change	Total Rate Change

0.0% 0.0%

--

October 2023 Rates		
Delivery	Generation	Total Rate

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

Delivery Change	Generation Change	Total Rate Change

GS-2 (TOU Rate R) - GF

Energy Charge - \$/kWh

Summer Season

On-Peak
Mid-peak
Off-Peak

Winter Season

Mid-peak
Off-Peak

Customer Charge - \$/month

Facilities Related Demand Charge - \$/kW

Single Phase Service - \$/month

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV
From 51 kV to 219 kV
220 kV and above

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV
From 51 kV to 219 kV
220 kV and above

TOU Rate Meter Charge - \$/month

TOU-RTEM

California Climate Credit - \$/kWh/Meter/Month

GS-APS-E (Schedules: GS-1 and TOU-GS-1)

Air Conditioning Cycling Credit - \$/ton/summer season day

30% Cycling
40% Cycling
50% Cycling
100% Cycling

GS-APS-E (Schedules: GS-2, TOU-GS-3, or TOU-8)

Air Conditioning Cycling Credit - \$/ton/summer season month

30% Cycling
40% Cycling
50% Cycling
100% Cycling

TOU-EV-8

Energy Charge - \$/kWh

Summer Season On-Peak
Mid-Peak
Off-Peak

Winter Season On-Peak
Mid-Peak
Off-Peak

Customer Charge - \$/meter/month

EV Submeter Credit - \$/Meter/Month

Facilities Related

Demand Charge - \$/kW

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV
From 51 kV to 219 kV
220 kV and above

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV
From 51 kV to 219 kV
220 kV and above

Power Factor Adjustment - \$/kVA

Greater than 50 kV
50 kV or less

California Climate Credit - \$/kWh/Meter/Month

--

TOU-GS-3 (Rate D)

Energy Charge - \$/kWh

Summer Season

On-Peak

0.04344 0.14288 0.18632

0.04267 0.14331 0.18598

-1.8% 0.3% -0.2%

Mid-peak

0.04225 0.13029 0.17254

0.04171 0.12024 0.16195

-1.3% -7.7% -6.1%

Off-Peak

0.04200 0.08799 0.12999

0.04150 0.10011 0.14161

-1.2% 13.8% 8.9%

Winter Season

Mid-peak

0.04344 0.10154 0.14498

0.04267 0.11533 0.15800

-1.8% 13.6% 9.0%

Off-Peak

0.04225 0.10216 0.14441

0.04171 0.11113 0.15284

-1.3% 8.8% 5.8%

Super-Off-Peak

0.04157 0.05366 0.09523

0.04117 0.06865 0.10982

-1.0% 27.9% 15.3%

Customer Charge - \$/month

544.34 0.00 544.34

748.75 0.00 748.75

37.6% 37.6%

Facilities Related

Demand Charge - \$/kW

20.01 0.00 20.01

20.20 0.00 20.20

0.9% 0.9%

Time Related Demand Charge - \$/kW

Summer Season

On-Peak

14.75 24.54 39.29

11.20 13.52 24.72

-24.1% -44.9% -37.1%

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Winter Season

Mid-Peak

2.62 8.88 11.50

2.98 5.68 8.66

13.7% -36.0% -24.7%

Off-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV

(0.28) 0.00 (0.28)

(0.37) 0.00 (0.37)

32.1% 32.1%

From 51 kV to 219 kV

(6.10) 0.00 (6.10)

(7.50) 0.00 (7.50)

23.0% 23.0%

220 kV and above

(14.75) 0.00 (14.75)

(14.94) 0.00 (14.94)

1.3% 1.3%

Voltage Discount, Time-Related Demand - \$/kW

Summer Season

From 2 kV to 50 kV

(0.27) (0.57) (0.84)

(0.28) (0.30) (0.58)

3.7% -47.4% -31.0%

From 51 kV to 219 kV

(5.08) (1.31) (6.39)

(3.83) (0.70) (4.53)

-24.6% -46.6% -29.1%

220 kV and above

(14.75) (1.32) (16.07)

(11.20) (0.71) (11.91)

-24.1% -46.2% -25.9%

Winter Season

From 2 kV to 50 kV

(0.27) (0.57) (0.84)

(0.07) (0.13) (0.20)

-74.1% -77.2% -76.2%

From 51 kV to 219 kV

(5.08) (1.31) (6.39)

(1.02) (0.29) (1.31)

-79.9% -77.9% -79.5%

220 kV and above

(14.75) (1.32) (16.07)

(2.98) (0.29) (3.27)

-79.8% -78.0% -79.7%

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV

(0.00022) (0.00128) (0.00150)

(0.00024) (0.00132) (0.00156)

9.1% 3.1% 4.0%

From 51 kV to 219 kV

(0.00415) (0.00279) (0.00694)

(0.00329) (0.00286) (0.00615)

-20.7% 2.5% -11.4%

220 kV and above

(0.01215) (0.00282) (0.01497)

(0.00979) (0.00289) (0.01268)

-19.4% 2.5% -15.3%

Power Factor Adjustment - \$/kVA

Greater than 50 kV

0.66 0.00 0.66

0.76 0.00 0.76

15.2% 15.2%

50 kV or less

0.52 0.00 0.52

0.60 0.00 0.60

15.4% 15.4%

TOU-GS-3 (Rate E)

Energy Charge - \$/kWh

Summer Season

On-Peak

0.33528 0.42199 0.75727

0.26309 0.30157 0.56466

-21.5% -28.5% -25.4%

Mid-peak

0.19020 0.13029 0.32049

0.15693 0.12024 0.27717

-17.5% -7.7% -13.5%

Off-Peak

0.11008 0.08799 0.19807

0.09867 0.16355 0.26222

-10.4% 85.9% 32.4%

Winter Season

Mid-peak

0.05677 0.16345 0.22022

0.05685 0.16950 0.22635

0.1% 3.7% 2.8%

Off-Peak

0.04099 0.10216 0.14315

0.04339 0.11113 0.15452

5.9% 8.8% 7.9%

Super-Off-Peak

0.05201 0.05366 0.10567

0.05777 0.06865 0.12642

11.1% 27.9% 19.6%

Customer Charge - \$/month

544.34 0.00 544.34

748.75 0.00 748.75

37.6% 37.6%

Facilities Related

Demand Charge - \$/kW

12.74 0.00 12.74

12.21 0.00 12.21

-4.2% -4.2%

Time Related Demand Charge - \$/kW

Summer Season

On-Peak

0.00 6.90 6.90

0.00 3.61 3.61

-47.7% -47.7%

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Winter Season

Mid-Peak

0.00 3.68 3.68

0.00 1.35 1.35

-63.3% -63.3%

Off-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV

(0.14) 0.00 (0.14)

(0.17) 0.00 (0.17)

21.4% 21.4%

From 51 kV to 219 kV

(3.09) 0.00 (3.09)

(3.49) 0.00 (3.49)

12.9% 12.9%

220 kV and above

(7.48) 0.00 (7.48)

(6.95) 0.00 (6.95)

-7.1% -7.1%

Voltage Discount, Time Related Demand - \$/kW

Summer Season

From 2 kV to 50 kV

0.00 (0.24) (0.24)

0.00 (0.07) (0.07)

-70.8% -70.8%

From 51 kV to 219 kV

0.00 (0.54) (0.54)

0.00 (0.17) (0.17)

-68.5% -68.5%

220 kV and above

0.00 (0.55) (0.55)

0.00 (0.17) (0.17)

-69.1% -69.1%

Winter Season

From 2 kV to 50 kV

0.00 (0.24) (0.24)

0.00 0.00 0.00

-100.0% -100.0%

From 51 kV to 219 kV

0.00 (0.54) (0.54)

0.00 0.00 0.00

-100.0% -100.0%

220 kV and above

0.00 (0.55) (0.55)

0.00 0.00 0.00

-100.0% -100.0%

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV

(0.00095) (0.00234) (0.00329)

(0.00110) (0.00192) (0.00302)

15.8% -17.9% -8.2%

From 51 kV to 219 kV

(0.01980) (0.00522) (0.02502)

(0.01896) (0.00426) (0.02322)

-4.2% -18.4% -7.2%

220 kV and above

(0.05335) (0.00526) (0.05861)

(0.04434) (0.00431) (0.04865)

-16.9% -18.1% -17.0%

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Power Factor Adjustment - \$/kVA

Greater than 50 kV
50 kV or less

October 2023 Rates		
Delivery	Generation	Total Rate

0.66 0.00 0.66
0.52 0.00 0.52

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

0.76 0.00 0.76
0.60 0.00 0.60

Delivery Change	Generation Change	Total Rate Change
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15.2% 15.2%
15.4% 15.4%

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October 2023 Rates		
Delivery	Generation	Total Rate

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

Delivery Change	Generation Change	Total Rate Change

TOU-GS-3-CPP

Critical Peak Pricing

Time-of-Use Pricing Rate Energy Charge - \$/kWh

Summer Season										
	On-Peak	0.04344	0.14288	0.18632	0.04267	0.14331	0.18598	-1.8%	0.3%	-0.2%
	Mid-peak	0.04225	0.13029	0.17254	0.04171	0.12024	0.16195	-1.3%	-7.7%	-6.1%
	Off-Peak	0.04200	0.08799	0.12999	0.04150	0.10011	0.14161	-1.2%	13.8%	8.9%
Winter Season										
	Mid-peak	0.04344	0.10154	0.14498	0.04267	0.11533	0.15800	-1.8%	13.6%	9.0%
	Off-Peak	0.04225	0.10216	0.14441	0.04171	0.11113	0.15284	-1.3%	8.8%	5.8%
	Super-Off-Peak	0.04157	0.05366	0.09523	0.04117	0.06865	0.10982	-1.0%	27.9%	15.3%
Customer Charge - \$/month		544.34	0.00	544.34	748.75	0.00	748.75	37.6%		37.6%
Facilities Related Demand Charge - \$/kW		20.01	0.00	20.01	20.20	0.00	20.20	0.9%		0.9%
Time Related Demand Charge - \$/kW										
Summer Season										
	On-Peak	14.75	24.54	39.29	11.20	13.52	24.72	-24.1%	-44.9%	-37.1%
	Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season										
	Mid-Peak	2.62	8.88	11.50	2.98	5.68	8.66	13.7%	-36.0%	-24.7%
Voltage Discount, Facilities Related Demand - \$/kW										
	From 2 kV to 50 kV	(0.28)	0.00	(0.28)	(0.37)	0.00	(0.37)	32.1%		32.1%
	From 51 kV to 219 kV	(6.10)	0.00	(6.10)	(7.50)	0.00	(7.50)	23.0%		23.0%
	220 kV and above	(14.75)	0.00	(14.75)	(14.94)	0.00	(14.94)	1.3%		1.3%
Voltage Discount, Time-Related Demand - \$/kW										
Summer Season										
	From 2 kV to 50 kV	(0.27)	(0.57)	(0.84)	(0.28)	(0.30)	(0.58)	3.7%	-47.4%	-31.0%
	From 51 kV to 219 kV	(5.08)	(1.31)	(6.39)	(3.83)	(0.70)	(4.53)	-24.6%	-46.6%	-29.1%
	220 kV and above	(14.75)	(1.32)	(16.07)	(11.20)	(0.71)	(11.91)	-24.1%	-46.2%	-25.9%
Winter Season										
	From 2 kV to 50 kV	(0.27)	(0.57)	(0.84)	(0.07)	(0.13)	(0.20)	-74.1%	-77.2%	-76.2%
	From 51 kV to 219 kV	(5.08)	(1.31)	(6.39)	(1.02)	(0.29)	(1.31)	-79.9%	-77.9%	-79.5%
	220 kV and above	(14.75)	(1.32)	(16.07)	(2.98)	(0.29)	(3.27)	-79.8%	-78.0%	-79.7%
Voltage Discount, Energy - \$/kWh										
	From 2 kV to 50 kV	(0.00022)	(0.00128)	(0.00150)	(0.00024)	(0.00132)	(0.00156)	9.1%	3.1%	4.0%
	From 51 kV to 219 kV	(0.00415)	(0.00279)	(0.00694)	(0.00329)	(0.00286)	(0.00615)	-20.7%	2.5%	-11.4%
	220 kV and above	(0.01215)	(0.00282)	(0.01497)	(0.00979)	(0.00289)	(0.01268)	-19.4%	2.5%	-15.3%
Power Factor Adjustment - \$/kVA										
	Greater than 50 kV	0.66	0.00	0.66	0.76	0.00	0.76	15.2%		15.2%
	50 kV or less	0.52	0.00	0.52	0.60	0.00	0.60	15.4%		15.4%
CPP Event Energy Charge - \$/kWh		0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
Summer CPP Non-Event Credit										
On-Peak Demand Credit - \$/kW		0.00	(7.55)	(7.55)	0.00	(7.55)	(7.55)		0.0%	0.0%

TOU-GS-3-RTP

Energy Charge - \$/kWh

Summer Season										
	On-Peak	0.04344	Variable*	Variable*	0.04267	Variable*	Variable*	-1.8%		
	Mid-peak	0.04225	Variable*	Variable*	0.04171	Variable*	Variable*	-1.3%		
	Off-Peak	0.04200	Variable*	Variable*	0.04150	Variable*	Variable*	-1.2%		
Winter Season										
	Mid-peak	0.04344	Variable*	Variable*	0.04267	Variable*	Variable*	-1.8%		
	Off-Peak	0.04225	Variable*	Variable*	0.04171	Variable*	Variable*	-1.3%		
	Super-Off-Peak	0.04157	Variable*	Variable*	0.04117	Variable*	Variable*	-1.0%		
Customer Charge - \$/month		544.34	0.00	544.34	748.75	0.00	748.75	37.6%		37.6%
Facilities Related Demand Charge - \$/kW		20.01	0.00	20.01	20.20	0.00	20.20	0.9%		0.9%
Time Related Demand Charge - \$/kW										
Summer Season										
	On-Peak	14.75	0.00	14.75	11.20	0.00	11.20	-24.1%		-24.1%
	Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season										
	Mid-Peak	2.62	0.00	2.62	2.98	0.00	2.98	13.7%		13.7%
	Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Voltage Discount, Facilities Related Demand - \$/kW										
	From 2 kV to 50 kV	(0.28)	0.00	(0.28)	(0.37)	0.00	(0.37)	32.1%		32.1%
	Above 50 kV but below 220 kV	(6.10)	0.00	(6.10)	(7.50)	0.00	(7.50)	23.0%		23.0%
	At 220 kV	(14.75)	0.00	(14.75)	(14.94)	0.00	(14.94)	1.3%		1.3%
Voltage Discount, Time-Related Demand - \$/kW										
Summer Season										
	From 2 kV to 50 kV	(0.27)	0.00	(0.27)	(0.28)	0.00	(0.28)	3.7%		3.7%
	From 51 kV to 219 kV	(5.08)	0.00	(5.08)	(3.83)	0.00	(3.83)	-24.6%		-24.6%
	220 kV and above	(14.75)	0.00	(14.75)	(11.20)	0.00	(11.20)	-24.1%		-24.1%
Winter Season										
	From 2 kV to 50 kV	(0.27)	0.00	(0.27)	(0.07)	0.00	(0.07)	-74.1%		-74.1%
	From 51 kV to 219 kV	(5.08)	0.00	(5.08)	(1.02)	0.00	(1.02)	-79.9%		-79.9%
	220 kV and above	(14.75)	0.00	(14.75)	(2.98)	0.00	(2.98)	-79.8%		-79.8%
Voltage Discount, Energy - \$/kWh										
	From 2 kV to 50 kV	(0.00022)	(0.00234)	(0.00256)	(0.00024)	(0.00192)	(0.00216)	9.1%	-17.9%	-15.6%
	From 51 kV to 219 kV	(0.00415)	(0.00522)	(0.00937)	(0.00329)	(0.00426)	(0.00755)	-20.7%	-18.4%	-19.4%
	220 kV and above	(0.01215)	(0.00526)	(0.01741)	(0.00979)	(0.00431)	(0.01410)	-19.4%	-18.1%	-19.0%

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Power Factor Adjustment - \$/kVA

Greater than 50 kV
50 kV or less

October 2023 Rates		
Delivery	Generation	Total Rate

0.66 0.00 0.66
0.52 0.00 0.52

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

0.76 0.00 0.76
0.60 0.00 0.60

Delivery Change	Generation Change	Total Rate Change
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15.2% 15.2%
15.4% 15.4%

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October 2023 Rates		
Delivery	Generation	Total Rate

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

Delivery Change	Generation Change	Total Rate Change

TOU-GS-3 (Rate B) - GF

Energy Charge - \$/kWh

Summer Season									
On-Peak	0.03010	0.10630	0.13640	0.03192	0.11576	0.14768	6.0%	8.9%	8.3%
Mid-peak	0.03010	0.09926	0.12936	0.03192	0.10815	0.14007	6.0%	9.0%	8.3%
Off-Peak	0.03010	0.09567	0.12577	0.03192	0.10418	0.13610	6.0%	8.9%	8.2%
Winter Season									
Mid-peak	0.03010	0.13493	0.16503	0.03192	0.13232	0.16424	6.0%	-1.9%	-0.5%
Off-Peak	0.03010	0.07861	0.10871	0.03192	0.09046	0.12238	6.0%	15.1%	12.6%
Customer Charge - \$/month	544.34	0.00	544.34	748.75	0.00	748.75	37.6%		37.6%
Facilities Related									
Demand Charge - \$/kW	30.19	0.00	30.19	28.44	0.00	28.44	-5.8%		-5.8%
Time Related Demand Charge - \$/kW									
Summer Season									
On-Peak	0.00	16.44	16.44	0.00	8.89	8.89		-45.9%	-45.9%
Mid-Peak	0.00	5.49	5.49	0.00	2.87	2.87		-47.7%	-47.7%
Winter Season									
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Off-Peak	0.00	0.00		0.00	0.00	0.00			
Voltage Discount, Facilities Related Demand - \$/kW									
From 2 kV to 50 kV	-0.58	0.00	(0.58)	-0.68	0.00	(0.68)	17.2%		17.2%
From 51 kV to 219 kV	-11.83	0.00	(11.83)	-11.74	0.00	(11.74)	-0.8%		-0.8%
220 kV and above	-24.93	0.00	(24.93)	-23.18	0.00	(23.18)	-7.0%		-7.0%
Voltage Discount, Time-Related Demand - \$/kW									
From 2 kV to 50 kV	0.00	-0.69	(0.69)	0.00	-0.34	(0.34)		-50.7%	-50.7%
From 51 kV to 219 kV	0.00	-1.58	(1.58)	0.00	-0.80	(0.80)		-49.4%	-49.4%
220 kV and above	0.00	-1.60	(1.60)	0.00	-0.82	(0.82)		-48.8%	-48.8%
Voltage Discount, Energy - \$/kWh									
From 2 kV to 50 kV	0.00000	-0.00128	(0.00128)	0.00000	-0.00132	(0.00132)		3.1%	3.1%
From 51 kV to 219 kV	0.00000	-0.00279	(0.00279)	0.00000	-0.00286	(0.00286)		2.5%	2.5%
220 kV and above	0.00000	-0.00282	(0.00282)	0.00000	-0.00289	(0.00289)		2.5%	2.5%
Power Factor Adjustment - \$/kVA									
Greater than 50 kV	0.66	0.00	0.66	0.76	0.00	0.76	15.2%		15.2%
50 kV or less	0.52	0.00	0.52	0.60	0.00	0.60	15.4%		15.4%

TOU-GS-3 (Rate R) - GF

Energy Charge - \$/kWh

Summer Season									
On-Peak	0.22517	0.30875	0.53392	0.18641	0.22643	0.41284	-17.2%	-26.7%	-22.7%
Mid-peak	0.12633	0.15223	0.27856	0.10882	0.13706	0.24588	-13.9%	-10.0%	-11.7%
Off-Peak	0.06371	0.09567	0.15938	0.05927	0.10418	0.16345	-7.0%	8.9%	2.6%
Winter Season									
Mid-peak	0.04726	0.13493	0.18219	0.04679	0.13232	0.17911	-1.0%	-1.9%	-1.7%
Off-Peak	0.03408	0.07861	0.11269	0.03524	0.09046	0.12570	3.4%	15.1%	11.5%
Customer Charge - \$/month	544.34	0.00	544.34	748.75	0.00	748.75	37.6%		37.6%
Facilities Related									
Demand Charge - \$/kW	18.68	0.00	18.68	17.74	0.00	17.74	-5.0%		-5.0%
Voltage Discount, Facilities Related Demand - \$/kW									
From 2 kV to 50 kV	-0.31	0.00	(0.31)	-0.37	0.00	(0.37)	19.4%		19.4%
From 51 kV to 219 kV	-6.37	0.00	(6.37)	-6.32	0.00	(6.32)	-0.8%		-0.8%
220 kV and above	-13.42	0.00	(13.42)	-12.48	0.00	(12.48)	-7.0%		-7.0%
Voltage Discount, Energy - \$/kWh									
From 2 kV to 50 kV	-0.00079	-0.00274	(0.00353)	-0.00095	-0.00211	(0.00306)	20.3%	-23.0%	-13.3%
From 51 kV to 219 kV	-0.01594	-0.00615	(0.02209)	-0.01635	-0.00469	(0.02104)	2.6%	-23.7%	-4.8%
220 kV and above	-0.03360	-0.00621	(0.03981)	-0.03228	-0.00475	(0.03703)	-3.9%	-23.5%	-7.0%
Power Factor Adjustment - \$/kVA									
Greater than 50 kV	0.66	0.00	0.66	0.76	0.00	0.76	15.2%		15.2%
50 kV or less	0.52	0.00	0.52	0.60	0.00	0.60	15.4%		15.4%

TOU-EV-9 (Below 2kV)

Energy Charge - \$/kWh

Summer Season									
On-Peak	0.20136	0.37869	0.58005	0.27349	0.33871	0.61220	35.8%	-10.6%	5.5%
Off-Peak	0.20136	0.12833	0.32969	0.17742	0.12013	0.29755	-11.9%	-6.4%	-9.7%
SOOff-Peak	0.09692	0.09966	0.19658	0.12189	0.10014	0.22203	25.8%	0.5%	12.9%
Winter Season									
On-Peak	0.20136	0.18678	0.38814	0.08665	0.19137	0.27802	-57.0%	2.5%	-28.4%
Off-Peak	0.09692	0.11441	0.21133	0.07426	0.11114	0.18540	-23.4%	-2.9%	-12.3%
SOOff-Peak	0.06394	0.05300	0.11694	0.08748	0.06863	0.15611	36.8%	29.5%	33.5%
Customer Charge - \$/month	355.45		355.45	1641.00		1641.00	361.7%		361.7%
Facilities Related Demand Charge - \$/kW	0.00			0.00		0.00			
Power Factor Adjustment - \$/kVA	0.52		0.52	0.60		0.60	15.4%		15.4%

			October 2023 Rates			Proposed 2025 GRC Rates					
			Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-EV-9 (From 2 kV to 50 kV)											
Energy Charge - \$/kWh											
Summer Season											
On-Peak			0.17837	0.34748	0.52585	0.26560	0.34787	0.61347	48.9%	0.1%	16.7%
Off-Peak			0.17837	0.12315	0.30152	0.17069	0.11869	0.28938	-4.3%	-3.6%	-4.0%
SOOff-Peak			0.08439	0.09426	0.17865	0.11297	0.09753	0.21050	33.9%	3.5%	17.8%
Winter Season											
On-Peak			0.17837	0.18626	0.36463	0.08166	0.19090	0.27256	-54.2%	2.5%	-25.3%
Off-Peak			0.08439	0.10788	0.19227	0.06947	0.10886	0.17833	-17.7%	0.9%	-7.3%
SOOff-Peak			0.05890	0.05095	0.10985	0.08243	0.06721	0.14964	39.9%	31.9%	36.2%
Customer Charge - \$/month			367.81		367.81	202.50		202.50	-44.9%		-44.9%
Facilities Related Demand Charge - \$/kW			0.00			0.00		0.00			
Power Factor Adjustment - \$/kVA			0.52		0.52	0.60		0.60	15.4%		15.4%
TOU-EV-9 (Above 50 kV)											
Energy Charge - \$/kWh											
Summer Season											
On-Peak			0.07399	0.33887	0.41286	0.09676	0.32678	0.42354	30.8%	-3.6%	2.6%
Off-Peak			0.07399	0.11593	0.18992	0.07787	0.11431	0.19218	5.2%	-1.4%	1.2%
SOOff-Peak			0.04182	0.08790	0.12972	0.05529	0.09448	0.14977	32.2%	7.5%	15.5%
Winter Season											
On-Peak			0.07399	0.16520	0.23919	0.04820	0.18605	0.23425	-34.9%	12.6%	-2.1%
Off-Peak			0.04182	0.10007	0.14189	0.04348	0.10615	0.14963	4.0%	6.1%	5.5%
SOOff-Peak			0.03539	0.04787	0.08326	0.04699	0.06555	0.11254	32.8%	36.9%	35.2%
Customer Charge - \$/month			3458.53		3,458.53	3828.75		3828.75	10.7%		10.7%
Facilities Related Demand Charge - \$/kW			0.00			0.00		0.00			
Power Factor Adjustment - \$/kVA			0.66		0.66	0.76		0.76	15.2%		15.2%
Voltage Discount, 220 kV and above (Demand - \$/kW)											
Facilities Related			0.00			0.00		0.00			
Voltage Discount, 220 kV and above (Energy - \$/kWh)			(0.02002)	(0.00131)	(0.02133)	(0.02160)	(0.00126)	(0.02286)	7.9%	-3.8%	7.2%
TOU-8-Rate D (Below 2kV)											
Energy Charge - \$/kWh											
Summer Season											
On-Peak			0.03941	0.14073	0.18014	0.03943	0.14320	0.18263	0.1%	1.8%	1.4%
Mid-peak			0.03829	0.12833	0.16662	0.03852	0.12013	0.15865	0.6%	-6.4%	-4.8%
Off-Peak			0.03806	0.08695	0.12501	0.03834	0.10014	0.13848	0.7%	15.2%	10.8%
Winter Season											
Mid-peak			0.03941	0.10035	0.13976	0.03943	0.11536	0.15479	0.1%	15.0%	10.8%
Off-Peak			0.03829	0.10097	0.13926	0.03852	0.11114	0.14966	0.6%	10.1%	7.5%
Super-Off-Peak			0.03764	0.05300	0.09064	0.03800	0.06863	0.10663	1.0%	29.5%	17.6%
Customer Charge - \$/month			355.45	0.00	355.45	1,641.00	0.00	1,641.00	361.7%		361.7%
Facilities Related											
Demand Charge - \$/kW			21.97	0.00	21.97	20.73	0.00	20.73	-5.6%		-5.6%
Time Related Demand Charge - \$/kW											
Summer Season											
On-Peak			16.16	25.52	41.68	11.79	13.89	25.68	-27.0%	-45.6%	-38.4%
Mid-Peak			0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season											
Mid-Peak			2.77	7.82	10.59	3.19	6.80	9.99	15.2%	-13.0%	-5.7%
Off-Peak			0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - \$/kVA			0.52	0.00	0.52	0.60	0.00	0.60	15.4%		15.4%

			October 2023 Rates			Proposed 2025 GRC Rates					
			Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8 (Below 2kV) - Rate E											
Energy Charge - \$/kWh											
Summer Season											
On-Peak			0.30231	0.40253	0.70484	0.24085	0.28653	0.52738	-20.3%	-28.8%	-25.2%
Mid-peak			0.17416	0.12833	0.30249	0.14478	0.12013	0.26491	-16.9%	-6.4%	-12.4%
Off-Peak			0.09609	0.08695	0.18304	0.08925	0.10014	0.18939	-7.1%	15.2%	3.5%
Winter Season											
Mid-peak			0.05252	0.15099	0.20351	0.05401	0.17326	0.22727	2.8%	14.7%	11.7%
Off-Peak			0.03829	0.10097	0.13926	0.04162	0.11114	0.15276	8.7%	10.1%	9.7%
Super-Off-Peak			0.04812	0.05300	0.10112	0.05484	0.06863	0.12347	14.0%	29.5%	22.1%
Customer Charge - \$/month			355.45	0.00	355.45	1641.00	0.00	1641.00	361.7%		361.7%
Facilities Related											
Demand Charge - \$/kW			13.58	0.00	13.58	12.61	0.00	12.61	-7.1%		-7.1%
Time Related Demand Charge - \$/kW											
Summer Season											
On-Peak			0.00	7.18	7.18	0.00	3.71	3.71		-48.3%	-48.3%
Mid-Peak			0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season											
Mid-Peak			0.00	3.24	3.24	0.00	1.62	1.62		-50.0%	-50.0%
Off-Peak			0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - \$/kVA			0.52	0.00	0.52	0.60	0.00	0.60	15.4%		15.4%
TOU-8-Rate B (Below 2kV) - GF											
Energy Charge - \$/kWh											
Summer Season											
On-Peak			0.02900	0.10489	0.13389	0.03141	0.11598	0.14739	8.3%	10.6%	10.1%
Mid-peak			0.02900	0.09760	0.12660	0.03141	0.10796	0.13937	8.3%	10.6%	10.1%
Off-Peak			0.02900	0.09440	0.12340	0.03141	0.10438	0.13579	8.3%	10.6%	10.0%
Winter Season											
Mid-peak			0.02900	0.12807	0.15707	0.03141	0.13741	0.16882	8.3%	7.3%	7.5%
Off-Peak			0.02900	0.07898	0.10798	0.03141	0.09180	0.12321	8.3%	16.2%	14.1%
Customer Charge - \$/month			355.45	0.00	355.45	1,641.00	0.00	1,641.00	361.7%		361.7%
Facilities Related											
Demand Charge - \$/kW			32.19	0.00	32.19	28.95	0.00	28.95	-10.1%		-10.1%
Time Related Demand Charge - \$/kW											
Summer Season											
On-Peak			0.00	17.57	17.57	0.00	9.47	9.47		-46.1%	-46.1%
Mid-Peak			0.00	5.77	5.77	0.00	3.11	3.11		-46.1%	-46.1%
Winter Season											
Mid-Peak			0.00	0.00	0.00	0.00	0.00	0.00			
Off-Peak			0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - \$/kVA			0.52	0.00	0.52	0.60	0.00	0.60	15.4%		15.4%
TOU-8 (Below 2kV) - Rate R - GF											
Energy Charge - \$/kWh											
Summer Season											
On-Peak			0.20043	0.30668	0.50711	0.17839	0.22441	0.40280	-11.0%	-26.8%	-20.6%
Mid-peak			0.10851	0.14672	0.25523	0.09986	0.13410	0.23396	-8.0%	-8.6%	-8.3%
Off-Peak			0.05523	0.09440	0.14963	0.05455	0.10438	0.15893	-1.2%	10.6%	6.2%
Winter Season											
Mid-peak			0.04304	0.12807	0.17111	0.04446	0.13741	0.18187	3.3%	7.3%	6.3%
Off-Peak			0.03203	0.07898	0.11101	0.03414	0.09180	0.12594	6.6%	16.2%	13.4%
Customer Charge - \$/month			355.45	0.00	355.45	1641.00	0.00	1641.00	361.7%		361.7%
Facilities Related											
Demand Charge - \$/kW			20.02	0.00	20.02	18.27	0.00	18.27	-8.7%		-8.7%
Time Related Demand Charge - \$/kW											
Summer Season											
On-Peak											
Mid-Peak											
Winter Season											
Mid-Peak											
Off-Peak											
Power Factor Adjustment - \$/kVA			0.52	0.00	0.52	0.60	0.00	0.60	15.4%		15.4%

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October 2023 Rates		
Delivery	Generation	Total Rate

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

Delivery Change	Generation Change	Total Rate Change

TOU-8-Rate D (From 2 kV to 50 kV)

Energy Charge - \$/kWh

Summer Season

On-Peak

0.03611 0.13478 0.17089

0.03741 0.14122 0.17863

3.6% 4.8% 4.5%

Mid-peak

0.03518 0.12315 0.15833

0.03658 0.11869 0.15527

4.0% -3.6% -1.9%

Off-Peak

0.03500 0.08326 0.11826

0.03642 0.09753 0.13395

4.1% 17.1% 13.3%

Winter Season

Mid-peak

0.03611 0.09632 0.13243

0.03741 0.11276 0.15017

3.6% 17.1% 13.4%

Off-Peak

0.03518 0.09712 0.13230

0.03658 0.10886 0.14544

4.0% 12.1% 9.9%

Super-Off-Peak

0.03460 0.05095 0.08555

0.03607 0.06721 0.10328

4.2% 31.9% 20.7%

Customer Charge - \$/month

367.81 0.00 367.81

202.50 0.00 202.50

-44.9% -44.9%

Facilities Related

Demand Charge - \$/kW

21.42 0.00 21.42

21.06 0.00 21.06

-1.7% -1.7%

Time Related Demand Charge - \$/kW

Summer Season

On-Peak

14.57 24.55 39.12

12.07 15.31 27.38

-17.2% -37.6% -30.0%

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Winter Season

Mid-Peak

2.63 9.19 11.82

3.33 7.78 11.11

26.6% -15.3% -6.0%

Off-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Power Factor Adjustment - \$/kVA

0.52 0.00 0.52

0.60 0.00 0.60

15.4% 15.4%

TOU-8 (From 2 kV to 50 kV) - Rate E

Energy Charge - \$/kWh

Summer Season

On-Peak

0.27061 0.38268 0.65329

0.23581 0.31085 0.54666

-12.9% -18.8% -16.3%

Mid-peak

0.15493 0.12315 0.27808

0.14090 0.11869 0.25959

-9.1% -3.6% -6.6%

Off-Peak

0.08415 0.08326 0.16741

0.08318 0.09753 0.18071

-1.2% 17.1% 7.9%

Winter Season

Mid-peak

0.04875 0.17603 0.22478

0.05187 0.17644 0.22831

6.4% 0.2% 1.6%

Off-Peak

0.03567 0.09712 0.13279

0.03968 0.10886 0.14854

11.2% 12.1% 11.9%

Super-Off-Peak

0.04444 0.05095 0.09539

0.05264 0.06721 0.11985

18.5% 31.9% 25.6%

Customer Charge - \$/month

367.81 0.00 367.81

202.50 0.00 202.50

-44.9% -44.9%

Facilities Related

Demand Charge - \$/kW

13.06 0.00 13.06

12.67 0.00 12.67

-3.0% -3.0%

Time Related Demand Charge - \$/kW

Summer Season

On-Peak

0.00 6.03 6.03

0.00 2.74 2.74

-54.6% -54.6%

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Winter Season

Mid-Peak

0.00 1.05 1.05

0.00 1.44 1.44

37.1% 37.1%

Off-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Power Factor Adjustment - \$/kVA

0.52 0.00 0.52

0.60 0.00 0.60

15.4% 15.4%

TOU-8-Rate B (From 2 kV to 50 kV) - GF

Energy Charge - \$/kWh

Summer Season

On-Peak

0.02764 0.10077 0.12841

0.03007 0.11366 0.14373

8.8% 12.8% 11.9%

Mid-peak

0.02764 0.09334 0.12098

0.03007 0.10525 0.13532

8.8% 12.8% 11.9%

Off-Peak

0.02764 0.09069 0.11833

0.03007 0.10229 0.13236

8.8% 12.8% 11.9%

Winter Season

Mid-peak

0.02764 0.13310 0.16074

0.03007 0.14264 0.17271

8.8% 7.2% 7.4%

Off-Peak

0.02764 0.07766 0.10530

0.03007 0.09159 0.12166

8.8% 17.9% 15.5%

Customer Charge - \$/month

367.81 0.00 367.81

202.50 0.00 202.50

-44.9% -44.9%

Facilities Related

Demand Charge - \$/kW

30.62 0.00 30.62

29.33 0.00 29.33

-4.2% -4.2%

Time Related Demand Charge - \$/kW

Summer Season

On-Peak

0.00 17.28 17.28

0.00 10.71 10.71

-38.0% -38.0%

Mid-Peak

0.00 5.56 5.56

0.00 3.33 3.33

-40.1% -40.1%

Winter Season

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Off-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Power Factor Adjustment - \$/kVA

0.52 0.00 0.52

0.60 0.00 0.60

15.4% 15.4%

			October 2023 Rates			Proposed 2025 GRC Rates					
			Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8 (From 2 kV to 50 kV) - Rate R - GF											
Energy Charge - \$/kWh											
Summer Season											
On-Peak			0.18854	0.29629	0.48483	0.18324	0.23786	0.42110	-2.8%	-19.7%	-13.1%
Mid-peak			0.09792	0.13762	0.23554	0.09676	0.13294	0.22970	-1.2%	-3.4%	-2.5%
Off-Peak			0.04828	0.09069	0.13897	0.04997	0.10229	0.15226	3.5%	12.8%	9.6%
Winter Season											
Mid-peak			0.04048	0.13310	0.17358	0.04288	0.14264	0.18552	5.9%	7.2%	6.9%
Off-Peak			0.03001	0.07766	0.10767	0.03237	0.09159	0.12396	7.9%	17.9%	15.1%
Customer Charge - \$/month			367.81	0.00	367.81	202.50	0.00	202.50	-44.9%		-44.9%
Facilities Related											
Demand Charge - \$/kW			19.33	0.00	19.33	18.62	0.00	18.62	-3.7%		-3.7%
Time Related Demand Charge - \$/kW											
Summer Season											
On-Peak											
Mid-Peak											
Winter Season											
Mid-Peak											
Off-Peak											
Power Factor Adjustment - \$/kVA			0.52	0.00	0.52	0.60	0.00	0.60	15.4%		15.4%
TOU-8-Rate D (Above 50 kV)											
Energy Charge - \$/kWh											
Summer Season											
On-Peak			0.02181	0.12649	0.14830	0.02476	0.13555	0.16031	13.5%	7.2%	8.1%
Mid-peak			0.02181	0.11593	0.13774	0.02476	0.11431	0.13907	13.5%	-1.4%	1.0%
Off-Peak			0.02181	0.07794	0.09975	0.02476	0.09448	0.11924	13.5%	21.2%	19.5%
Winter Season											
Mid-peak			0.02181	0.09020	0.11201	0.02476	0.10956	0.13432	13.5%	21.5%	19.9%
Off-Peak			0.02181	0.09130	0.11311	0.02476	0.10615	0.13091	13.5%	16.3%	15.7%
Super-Off-Peak			0.02181	0.04787	0.06968	0.02476	0.06555	0.09031	13.5%	36.9%	29.6%
Customer Charge - \$/month			3,458.53	0.00	3,458.53	3,828.75	0.00	3,828.75	10.7%		10.7%
Facilities Related											
Demand Charge - \$/kW			10.63	0.00	10.63	11.48	0.00	11.48	8.0%		8.0%
Time Related Demand Charge - \$/kW											
Summer Season											
On-Peak			5.66	27.12	32.78	5.50	15.98	21.48	-2.8%	-41.1%	-34.5%
Mid-Peak			0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season											
Mid-Peak			0.65	8.77	9.42	0.79	9.05	9.84	21.5%	3.2%	4.5%
Off-Peak			0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - \$/kVA			0.66	0.00	0.66	0.76	0.00	0.76	15.2%		15.2%
Voltage Discount, 220 kV and above											
Facilities Related Demand - \$/kW			(5.04)	0.00	(5.04)	(6.23)	0.00	(6.23)	23.6%		23.6%
Time-Related Demand - \$/kW											
Summer On-Peak			(5.66)	(0.28)	(5.94)	(5.50)	(0.16)	(5.66)	-2.8%	-42.9%	-4.7%
Winter Mid-Peak			(5.66)	(0.28)	(5.94)	(0.79)	(0.09)	(0.88)	-86.0%	-67.9%	-85.2%
Energy - \$/kWh			0.00000	(0.00082)	(0.00082)	0.00000	(0.00098)	(0.00098)		19.5%	19.5%

			October 2023 Rates			Proposed 2025 GRC Rates					
			Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8 (Above 50 kV) - Rate E											
Energy Charge - \$/kWh											
Summer Season											
On-Peak			0.09200	0.42099	0.51299	0.09628	0.29761	0.39389	4.7%	-29.3%	-23.2%
Mid-peak			0.06299	0.11593	0.17892	0.07175	0.11431	0.18606	13.9%	-1.4%	4.0%
Off-Peak			0.03275	0.07794	0.11069	0.04242	0.09448	0.13690	29.5%	21.2%	23.7%
Winter Season											
Mid-peak			0.02842	0.15453	0.18295	0.03321	0.17538	0.20859	16.9%	13.5%	14.0%
Off-Peak			0.02342	0.09130	0.11472	0.02707	0.10615	0.13322	15.6%	16.3%	16.1%
Super-Off-Peak			0.02396	0.04787	0.07183	0.03164	0.06555	0.09719	32.1%	36.9%	35.3%
Customer Charge - \$/month			3458.53	0.00	3,458.53	3828.75	0.00	3828.75	10.7%		10.7%
Facilities Related											
Demand Charge - \$/kW			8.05	0.00	8.05	7.50	0.00	7.50	-6.8%		-6.8%
Time Related Demand Charge - \$/kW											
Summer Season											
On-Peak			0.00	2.57	2.57	0.00	2.44	2.44		-5.1%	-5.1%
Mid-Peak			0.00	0.00		0.00	0.00	0.00			
Winter Season											
Mid-Peak			0.00	1.25	1.25	0.00	1.26	1.26		0.8%	0.8%
Off-Peak			0.00	0.00		0.00	0.00	0.00			
Power Factor Adjustment - \$/kVA			0.66	0.00	0.66	0.76	0.00	0.76	15.2%		15.2%
Voltage Discount, 220 kV and above											
Facilities Related Demand - \$			(2.80)	0.00	(2.80)	(2.25)	0.00	(2.25)	-19.6%		-19.6%
Time-Related Demand - \$/kW											
Summer On-Peak			0.00	(0.03)	(0.03)	0.00	(0.02)	(0.02)		-33.3%	-33.3%
Winter Mid-Peak			0.00	(0.03)	(0.03)	0.00	(0.01)	(0.01)		-66.7%	-66.7%
Energy - \$/kWh			(0.00857)	(0.00106)	(0.00963)	(0.01186)	(0.00115)	(0.01301)	38.4%	8.5%	35.1%
TOU-8-Rate B (Above 50 kV) - GF											
Energy Charge - \$/kWh											
Summer Season											
On-Peak			0.02275	0.09440	0.11715	0.0257	0.10996	0.13566	13.0%	16.5%	15.8%
Mid-peak			0.02275	0.08715	0.10990	0.0257	0.10162	0.12732	13.0%	16.6%	15.9%
Off-Peak			0.02275	0.08496	0.10771	0.0257	0.09897	0.12467	13.0%	16.5%	15.7%
Winter Season											
Mid-peak			0.02275	0.12295	0.14570	0.0257	0.14198	0.16768	13.0%	15.5%	15.1%
Off-Peak			0.02275	0.07365	0.09640	0.0257	0.08966	0.11536	13.0%	21.7%	19.7%
Customer Charge - \$/month			3458.53	0.00	3,458.53	3828.75	0.00	3,828.75	10.7%		10.7%
Facilities Related											
Demand Charge - \$/kW			12.33	0.00	12.33	13.21	0.00	13.21	7.1%		7.1%
Time Related Demand Charge - \$/kW											
Summer Season											
On-Peak			0.00	19.75	19.75	0.00	11.75	11.75		-40.5%	-40.5%
Mid-Peak			0.00	6.40	6.40	0.00	3.77	3.77		-41.1%	-41.1%
Winter Season											
Mid-Peak			0.00	0.00		0.00	0.00	0.00			
Off-Peak			0.00	0.00		0.00	0.00	0.00			
Power Factor Adjustment - \$/kVA			0.66	0.00	0.66	0.76	0.00	0.76	15.2%		15.2%
Voltage Discount, 220 kV and above											
Facilities Related Demand - \$/kW			(7.08)	0.00	(7.08)	(7.96)	0.00	(7.96)	12.4%		12.4%
Time-Related Demand - \$/kW											
Summer			0.00	(0.41)	(0.41)	0.00	(0.23)	(0.23)		-43.9%	-43.9%
Energy - \$/kWh			0.00000	(0.00082)	(0.00082)	0.00000	(0.00098)	(0.00098)		19.5%	19.5%

	October 2023 Rates			Proposed 2025 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8 (Above 50 kV) - Rate R - GF									
Energy Charge - \$/kWh									
Summer Season									
On-Peak	0.07911	0.29414	0.37325	0.10585	0.22781	0.33366	33.8%	-22.6%	-10.6%
Mid-peak	0.04716	0.13105	0.17821	0.06029	0.12765	0.18794	27.8%	-2.6%	5.5%
Off-Peak	0.02926	0.08496	0.11422	0.03514	0.09897	0.13411	20.1%	16.5%	17.4%
Winter Season									
Mid-peak	0.02697	0.12295	0.14992	0.03199	0.14198	0.17397	18.6%	15.5%	16.0%
Off-Peak	0.02346	0.07365	0.09711	0.02673	0.08966	0.11639	13.9%	21.7%	19.9%
Customer Charge - \$/month	3458.53	0.00	3,458.53	3828.75	0.00	3828.75	10.7%		10.7%
Facilities Related									
Demand Charge - \$/kW	8.05	0.00	8.05	7.50	0.00	7.50	-6.8%		-6.8%
Time Related Demand Charge - \$/kW									
Summer Season									
On-Peak									
Mid-Peak									
Winter Season									
Mid-Peak									
Off-Peak									
Power Factor Adjustment - \$/kVA	0.66	0.00	0.66	0.76	0.00	0.76	15.2%		15.2%
Voltage Discount, 220 kV and above									
Facilities Related Demand - \$	(2.80)	0.00	(2.80)	(2.25)	0.00	(2.25)	-19.6%		-19.6%
Time-Related Demand - \$/kW									
Summer	0.00	0.00		0.00	0.00	0.00			
Energy - \$/kWh	(0.00829)	(0.00131)	(0.00960)	(0.01107)	(0.00126)	(0.01233)	33.5%	-3.8%	28.4%
TOU-8-Backup-D (Below 2kV)									
Energy Charge - \$/kWh									
Summer Season									
On-Peak	0.02900	0.14073	0.16973	0.03141	0.14320	0.17461	8.3%	1.8%	2.9%
Mid-peak	0.02900	0.12833	0.15733	0.03141	0.12013	0.15154	8.3%	-6.4%	-3.7%
Off-Peak	0.02900	0.08695	0.11595	0.03141	0.10014	0.13155	8.3%	15.2%	13.5%
Winter Season									
Mid-peak	0.02900	0.10035	0.12935	0.03141	0.11536	0.14677	8.3%	15.0%	13.5%
Off-Peak	0.02900	0.10097	0.12997	0.03141	0.11114	0.14255	8.3%	10.1%	9.7%
Super-Off-Peak	0.02900	0.05300	0.08200	0.03141	0.06863	0.10004	8.3%	29.5%	22.0%
Customer Charge - \$/month	301.42	0.00	301.42	1,486.00	0.00	1,486.00	393.0%		393.0%
Time Related Demand Charge - \$/kW									
Summer Season									
On-Peak	0.00	25.52	25.52	0.00	13.89	13.89		-45.6%	-45.6%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.00	7.82	7.82	0.00	6.80	6.80		-13.0%	-13.0%
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - \$/kVA	0.52	0.00	0.52	0.60	0.00	0.60	15.4%		15.4%
TOU-8-Backup-D (From 2 kV to 50 kV)									
Energy Charge - \$/kWh									
Summer Season									
On-Peak	0.02764	0.13478	0.16242	0.03007	0.14122	0.17129	8.8%	4.8%	5.5%
Mid-peak	0.02764	0.12315	0.15079	0.03007	0.11869	0.14876	8.8%	-3.6%	-1.3%
Off-Peak	0.02764	0.08326	0.11090	0.03007	0.09753	0.12760	8.8%	17.1%	15.1%
Winter Season									
Mid-peak	0.02764	0.09632	0.12396	0.03007	0.11276	0.14283	8.8%	17.1%	15.2%
Off-Peak	0.02764	0.09712	0.12476	0.03007	0.10886	0.13893	8.8%	12.1%	11.4%
Super-Off-Peak	0.02764	0.05095	0.07859	0.03007	0.06721	0.09728	8.8%	31.9%	23.8%
Customer Charge - \$/month	314.88	0.00	314.88	218.00	0.00	218.00	-30.8%		-30.8%
Time Related Demand Charge - \$/kW									
Summer Season									
On-Peak	0.00	24.55	24.55	0.00	15.31	15.31		-37.6%	-37.6%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.00	9.19	9.19	0.00	7.78	7.78		-15.3%	-15.3%
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - \$/kVA	0.52	0.00	0.52	0.60	0.00	0.60	15.4%		15.4%

			October 2023 Rates			Proposed 2025 GRC Rates					
			Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-Backup-D (Above 50 kV)											
Energy Charge - \$/kWh											
Summer Season											
On-Peak			0.02275	0.12649	0.14924	0.02570	0.13555	0.16125	13.0%	7.2%	8.0%
Mid-peak			0.02275	0.11593	0.13868	0.02570	0.11431	0.14001	13.0%	-1.4%	1.0%
Off-Peak			0.02275	0.07794	0.10069	0.02570	0.09448	0.12018	13.0%	21.2%	19.4%
Winter Season											
Mid-peak			0.02275	0.09020	0.11295	0.02570	0.10956	0.13526	13.0%	21.5%	19.8%
Off-Peak			0.02275	0.09130	0.11405	0.02570	0.10615	0.13185	13.0%	16.3%	15.6%
Super-Off-Peak			0.02275	0.04787	0.07062	0.02570	0.06555	0.09125	13.0%	36.9%	29.2%
Customer Charge - \$/month			3,387.15	0.00	3,387.15	3,464.00	0.00	3,464.00	2.3%		2.3%
Time Related Demand Charge - \$/kW											
Summer Season											
On-Peak			0.00	27.12	27.12	0.00	15.98	15.98		-41.1%	-41.1%
Mid-Peak			0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season											
Mid-Peak			0.00	8.77	8.77	0.00	9.05	9.05		3.2%	3.2%
Off-Peak			0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - \$/kVA			0.66	0.00	0.66	0.76	0.00	0.76	15.2%		15.2%
Voltage Discount, 220 kV and above											
Facilities Related Demand - \$/kW			0.00	0.00	0.00	0.00	0.00	0.00			
Time-Related Demand - \$/kW											
Summer On-Peak			0.00	(0.28)	(0.28)	0.00	(0.16)	(0.16)		-42.9%	-42.9%
Winter Mid-Peak			0.00	(0.28)	(0.28)	0.00	(0.09)	(0.09)		-67.9%	-67.9%
Energy - \$/kWh			0.00000	(0.00082)	(0.00082)	0.00000	(0.00098)	(0.00098)		19.5%	19.5%
TOU-8-CPP (Below 2kV)											
Critical Peak Pricing											
Energy Charge - \$/kWh											
Summer Season											
On-Peak			0.03941	0.14073	0.18014	0.03943	0.14320	0.18263	0.1%	1.8%	1.4%
Mid-peak			0.03829	0.12833	0.16662	0.03852	0.12013	0.15865	0.6%	-6.4%	-4.8%
Off-Peak			0.03806	0.08695	0.12501	0.03834	0.10014	0.13848	0.7%	15.2%	10.8%
Winter Season											
Mid-peak			0.03941	0.10035	0.13976	0.03943	0.11536	0.15479	0.1%	15.0%	10.8%
Off-Peak			0.03829	0.10097	0.13926	0.03852	0.11114	0.14966	0.6%	10.1%	7.5%
Super-Off-Peak			0.03764	0.05300	0.09064	0.03800	0.06863	0.10663	1.0%	29.5%	17.6%
Customer Charge - \$/month			355.45	0.00	355.45	1,641.00	0.00	1,641.00	361.7%		361.7%
Facilities Related											
Demand Charge - \$/kW			21.97	0.00	21.97	20.73	0.00	20.73	-5.6%		-5.6%
Time Related Demand Charge - \$/kW											
Summer Season											
On-Peak			16.16	25.52	41.68	11.79	13.89	25.68	-27.0%	-45.6%	-38.4%
Mid-Peak			0.00	0.00	0.00	0.00	0.00	0.00			
Off-Peak					0.00						
Winter Season											
Mid-Peak			2.77	7.82	10.59	3.19	6.80	9.99	15.2%	-13.0%	-5.7%
Off-Peak			0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - \$/kVA			0.52	0.00	0.52	0.60	0.00	0.60	15.4%		15.4%
CPP Event Energy Charge - \$/kWh			0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
Summer CPP Non-Event Credit											
On-Peak Demand Credit - \$/kW			0.00	(8.22)	(8.22)	0.00	(8.22)	(8.22)		0.0%	0.0%

			October 2023 Rates			Proposed 2025 GRC Rates					
			Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-CPP (From 2 kV to 50 kV)											
Critical Peak Pricing											
Energy Charge - \$/kWh											
Summer Season											
On-Peak			0.03611	0.13478	0.17089	0.03741	0.14122	0.17863	3.6%	4.8%	4.5%
Mid-peak			0.03518	0.12315	0.15833	0.03658	0.11869	0.15527	4.0%	-3.6%	-1.9%
Off-Peak			0.03500	0.08326	0.11826	0.03642	0.09753	0.13395	4.1%	17.1%	13.3%
Winter Season											
Mid-peak			0.03611	0.09632	0.13243	0.03741	0.11276	0.15017	3.6%	17.1%	13.4%
Off-Peak			0.03518	0.09712	0.13230	0.03658	0.10886	0.14544	4.0%	12.1%	9.9%
Super-Off-Peak			0.03460	0.05095	0.08555	0.03607	0.06721	0.10328	4.2%	31.9%	20.7%
Customer Charge - \$/month			367.81	0.00	367.81	202.50	0.00	202.50	-44.9%		-44.9%
Facilities Related											
Demand Charge - \$/kW			21.42	0.00	21.42	21.06	0.00	21.06	-1.7%		-1.7%
Time Related Demand Charge - \$/kW											
Summer Season											
On-Peak			14.57	24.55	39.12	12.07	15.31	27.38	-17.2%	-37.6%	-30.0%
Mid-Peak			0.00	0.00	0.00	0.00	0.00	0.00			
Off-Peak					0.00						
Winter Season											
Mid-Peak			2.63	9.19	11.82	3.33	7.78	11.11	26.6%	-15.3%	-6.0%
Off-Peak			0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - \$/kVA			0.52	0.00	0.52	0.60	0.00	0.60	15.4%		15.4%
CPP Event Energy Charge - \$/kWh			0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
Summer CPP Non-Event Credit											
On-Peak Demand Credit - \$/kW			0.00	(8.52)	(8.52)	0.00	(8.52)	(8.52)		0.0%	0.0%
TOU-8-CPP (Above 50 kV)											
Critical Peak Pricing											
Energy Charge - \$/kWh											
Summer Season											
On-Peak			0.02181	0.12649	0.14830	0.02476	0.13555	0.16031	13.5%	7.2%	8.1%
Mid-peak			0.02181	0.11593	0.13774	0.02476	0.11431	0.13907	13.5%	-1.4%	1.0%
Off-Peak			0.02181	0.07794	0.09975	0.02476	0.09448	0.11924	13.5%	21.2%	19.5%
Winter Season											
Mid-peak			0.02181	0.09020	0.11201	0.02476	0.10956	0.13432	13.5%	21.5%	19.9%
Off-Peak			0.02181	0.09130	0.11311	0.02476	0.10615	0.13091	13.5%	16.3%	15.7%
Super-Off-Peak			0.02181	0.04787	0.06968	0.02476	0.06555	0.09031	13.5%	36.9%	29.6%
Customer Charge - \$/month			3,458.53	0.00	3,458.53	3,828.75	0.00	3,828.75	10.7%		10.7%
Facilities Related											
Demand Charge - \$/kW			10.63	0.00	10.63	11.48	0.00	11.48	8.0%		8.0%
Time Related Demand Charge - \$/kW											
Summer Season											
On-Peak			5.66	27.12	32.78	5.50	15.98	21.48	-2.8%	-41.1%	-34.5%
Mid-Peak			0.00	0.00	0.00	0.00	0.00	0.00			
Off-Peak					0.00						
Winter Season											
Mid-Peak			0.65	8.77	9.42	0.79	9.05	9.84	21.5%	3.2%	4.5%
Off-Peak			0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - \$/kVA			0.66	0.00	0.66	0.76	0.00	0.76	15.2%		15.2%
CPP Event Energy Charge - \$/kWh			0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
Summer CPP Non-Event Credit											
On-Peak Demand Credit - \$/kW			0.00	(8.44)	(8.44)	0.00	(8.44)	(8.44)		0.0%	0.0%
Voltage Discount, 220 kV and above											
Facilities Related Demand - \$/kW			(5.04)	0.00	(5.04)	(6.23)	0.00	(6.23)	23.6%		23.6%
Time-Related Demand - \$/kW											
Summer On-Peak			(5.66)	(0.28)	(5.94)	(5.50)	(0.16)	(5.66)	-2.8%	-42.9%	-4.7%
Winter Mid-Peak			(5.66)	(0.28)	(5.94)	(0.79)	(0.09)	(0.88)	-86.0%	-67.9%	-85.2%
Energy - \$/kWh			0.00000	(0.00082)	(0.00082)	0.00000	(0.00098)	(0.00098)		19.5%	19.5%

			October 2023 Rates			Proposed 2025 GRC Rates					
			Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-RTP (Below 2kV)											
Energy Charge - \$/kWh											
Summer Season											
On-Peak			0.03941	Variable*	Variable*	0.03943	Variable*	Variable*	0.1%		
Mid-peak			0.03829	Variable*	Variable*	0.03852	Variable*	Variable*	0.6%		
Off-Peak			0.03806	Variable*	Variable*	0.03834	Variable*	Variable*	0.7%		
Winter Season											
Mid-peak			0.03941	Variable*	Variable*	0.03943	Variable*	Variable*	0.1%		
Off-Peak			0.03829	Variable*	Variable*	0.03852	Variable*	Variable*	0.6%		
Super-Off-Peak			0.03764	Variable*	Variable*	0.03800	Variable*	Variable*	1.0%		
Customer Charge - \$/month			355.45	0.00	355.45	1,641.00	0.00	1,641.00	361.7%		361.7%
Facilities Related											
Demand Charge - \$/kW			21.97	0.00	21.97	20.73	0.00	20.73	-5.6%		-5.6%
Time Related Demand Charge - \$/kW											
Summer Season											
On-Peak			16.16	0.00	16.16	11.79	0.00	11.79	-27.0%		-27.0%
Mid-Peak			0.00	0.00		0.00	0.00	0.00			
Winter Season											
Mid-Peak			2.77	0.00	2.77	3.19	0.00	3.19	15.2%		15.2%
Off-Peak			0.00	0.00		0.00	0.00	0.00			
Power Factor Adjustment - \$/kVA			0.52	0.00	0.52	0.60	0.00	0.60	15.4%		15.4%
TOU-8-RTP (From 2 kV to 50 kV)											
Energy Charge - \$/kWh											
Summer Season											
On-Peak			0.03611	Variable*	Variable*	0.03741	Variable*	Variable*	3.6%		
Mid-peak			0.03518	Variable*	Variable*	0.03658	Variable*	Variable*	4.0%		
Off-Peak			0.03500	Variable*	Variable*	0.03642	Variable*	Variable*	4.1%		
Winter Season											
Mid-peak			0.03611	Variable*	Variable*	0.03741	Variable*	Variable*	3.6%		
Off-Peak			0.03518	Variable*	Variable*	0.03658	Variable*	Variable*	4.0%		
Super-Off-Peak			0.03460	Variable*	Variable*	0.03607	Variable*	Variable*	4.2%		
Customer Charge - \$/month			367.81	0.00	367.81	202.50	0.00	202.50	-44.9%		-44.9%
Facilities Related											
Demand Charge - \$/kW			21.42	0.00	21.42	21.06	0.00	21.06	-1.7%		-1.7%
Time Related Demand Charge - \$/kW											
Summer Season											
On-Peak			14.57	0.00	14.57	12.07	0.00	12.07	-17.2%		-17.2%
Mid-Peak			0.00	0.00		0.00	0.00	0.00			
Winter Season											
Mid-Peak			2.63	0.00	2.63	3.33	0.00	3.33	26.6%		26.6%
Off-Peak			0.00	0.00		0.00	0.00	0.00			
Power Factor Adjustment - \$/kVA			0.52	0.00	0.52	0.60	0.00	0.60	15.4%		15.4%
TOU-8-RTP (Above 50 kV)											
Energy Charge - \$/kWh											
Summer Season											
On-Peak			0.02181	Variable*	Variable*	0.02476	Variable*	Variable*	13.5%		
Mid-peak			0.02181	Variable*	Variable*	0.02476	Variable*	Variable*	13.5%		
Off-Peak			0.02181	Variable*	Variable*	0.02476	Variable*	Variable*	13.5%		
Winter Season											
Mid-peak			0.02181	Variable*	Variable*	0.02476	Variable*	Variable*	13.5%		
Off-Peak			0.02181	Variable*	Variable*	0.02476	Variable*	Variable*	13.5%		
Super-Off-Peak			0.02181	Variable*	Variable*	0.02476	Variable*	Variable*	13.5%		
Customer Charge - \$/month			3,458.53	0.00	3,458.53	3,828.75	0.00	3,828.75	10.7%		10.7%
Facilities Related											
Demand Charge - \$/kW			10.63	0.00	10.63	11.48	0.00	11.48	8.0%		8.0%
Time Related Demand Charge - \$/kW											
Summer Season											
On-Peak			5.66	0.00	5.66	5.50	0.00	5.50	-2.8%		-2.8%
Mid-Peak			0.00	0.00		0.00	0.00	0.00			
Winter Season											
Mid-Peak			0.65	0.00	0.65	0.79	0.00	0.79	21.5%		21.5%
Off-Peak			0.00	0.00		0.00	0.00	0.00			
Power Factor Adjustment - \$/kVA			0.66	0.00	0.66	0.76	0.00	0.76	15.2%		15.2%
Voltage Discount, 220 kV and above											
Facilities Related Demand - \$/kW			(5.04)	0.00	(5.04)	(6.23)	0.00	(6.23)	23.6%		23.6%
Time-Related Demand - \$/kW											
Summer On-Peak			(5.66)	0.00	(5.66)	(5.50)	0.00	(5.50)	-2.8%		-2.8%
Winter Mid-Peak			(5.66)	0.00	(5.66)	(0.79)	0.00	(0.79)	-86.0%		-86.0%
Energy - \$/kWh			0.00000	(0.00082)	(0.00082)	0.00000	(0.00115)	(0.00115)		40.2%	40.2%

	October 2023 Rates			Proposed 2025 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-BIP Rate - \$/kW (Applicable: Average kW demand)									
Rate A									
BIP Rate Credit (\$/KW)									
Below 2 kV - Summer Average On Peak	(26.11)	(26.11)	(26.11)	(26.11)	(26.11)		0.0%		0.0%
Summer Average Mid - Peak	(2.04)	(2.04)	(2.04)	(2.04)	(2.04)		0.0%		0.0%
Winter Average Mid - Peak	(10.97)	(10.97)	(10.97)	(10.97)	(10.97)		0.0%		0.0%
Excess Energy Charge - \$/kWh	14.98186	14.98186	14.98186	14.98186	14.98186		0.0%		0.0%
From 2 kV to 50 kV - Summer Average On Peak	(26.11)	(26.11)	(26.11)	(26.11)	(26.11)		0.0%		0.0%
Summer Average Mid - Peak	(1.70)	(1.70)	(1.70)	(1.70)	(1.70)		0.0%		0.0%
Winter Average Mid - Peak	(10.26)	(10.26)	(10.26)	(10.26)	(10.26)		0.0%		0.0%
Excess Energy Charge - \$/kWh	14.69333	14.69333	14.69333	14.69333	14.69333		0.0%		0.0%
above 50 kV - Summer Average On Peak	(17.84)	(17.84)	(17.84)	(17.84)	(17.84)		0.0%		0.0%
Summer Average Mid - Peak	(0.86)	(0.86)	(0.86)	(0.86)	(0.86)		0.0%		0.0%
Winter Average Mid - Peak	(6.46)	(6.46)	(6.46)	(6.46)	(6.46)		0.0%		0.0%
Excess Energy Charge - \$/kWh	14.18881	14.18881	14.18881	14.18881	14.18881		0.0%		0.0%
Rate B									
BIP Rate Credit (\$/KW)									
Below 2 kV - Summer Average On Peak	(23.54)	(23.54)	(23.54)	(23.54)	(23.54)		0.0%		0.0%
Summer Average Mid - Peak	(1.84)	(1.84)	(1.84)	(1.84)	(1.84)		0.0%		0.0%
Winter Average Mid - Peak	(9.89)	(9.89)	(9.89)	(9.89)	(9.89)		0.0%		0.0%
Excess Energy Charge - \$/kWh	13.51232	13.51232	13.51232	13.51232	13.51232		0.0%		0.0%
From 2 kV to 50 kV - Summer Average On Peak	(23.14)	(23.14)	(23.14)	(23.14)	(23.14)		0.0%		0.0%
Summer Average Mid - Peak	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)		0.0%		0.0%
Winter Average Mid - Peak	(9.07)	(9.07)	(9.07)	(9.07)	(9.07)		0.0%		0.0%
Excess Energy Charge - \$/kWh	13.22378	13.22378	13.22378	13.22378	13.22378		0.0%		0.0%
above 50 kV - Summer Average On Peak	(15.37)	(15.37)	(15.37)	(15.37)	(15.37)		0.0%		0.0%
Summer Average Mid - Peak	(0.73)	(0.73)	(0.73)	(0.73)	(0.73)		0.0%		0.0%
Winter Average Mid - Peak	(5.54)	(5.54)	(5.54)	(5.54)	(5.54)		0.0%		0.0%
Excess Energy Charge - \$/kWh	12.71927	12.71927	12.71927	12.71927	12.71927		0.0%		0.0%
TOU-8-S Rate D (Below 2kV)									
Energy Charge - \$/kWh									
Summer Season									
On-Peak	0.03957	0.14073	0.18030	0.03900	0.14320	0.18220	-1.4%	1.8%	1.1%
Mid-peak	0.03845	0.12833	0.16678	0.03809	0.12013	0.15822	-0.9%	-6.4%	-5.1%
Off-Peak	0.03822	0.08695	0.12517	0.03791	0.10014	0.13805	-0.8%	15.2%	10.3%
Winter Season									
Mid-peak	0.03957	0.10035	0.13992	0.03900	0.11536	0.15436	-1.4%	15.0%	10.3%
Off-Peak	0.03845	0.10097	0.13942	0.03809	0.11114	0.14923	-0.9%	10.1%	7.0%
Super-Off-Peak	0.03780	0.05300	0.09080	0.03757	0.06863	0.10620	-0.6%	29.5%	17.0%
Customer Charge - \$/month	355.45	0.00	355.45	1,641.00	0.00	1,641.00	361.7%		361.7%
Facilities Related Demand									
Demand Charge (Excess FRD) - \$/kW	21.97	0.00	21.97	20.73	0.00	20.73	-5.6%		-5.6%
Standby (CRC) - \$/kW	18.75	0.00	18.75	15.93	0.00	15.93	-15.0%		-15.0%
Time Related Demand Charge - \$/kW									
Backup demand - Summer Season									
On-Peak	13.19	28.70	41.89	12.20	14.83	27.03	-7.5%	-48.3%	-35.5%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	2.34	12.95	15.29	3.39	6.48	9.87	44.9%	-50.0%	-35.4%
Supplemental demand - Summer Season									
On-Peak	16.16	25.52	41.68	11.79	13.89	25.68	-27.0%	-45.6%	-38.4%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	2.77	7.82	10.59	3.19	6.80	9.99	15.2%	-13.0%	-5.7%
Power Factor Adjustment - \$/kVA	0.52	0.00	0.52	0.60	0.00	0.60	15.4%		15.4%

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October 2023 Rates		
Delivery	Generation	Total Rate

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

Delivery Change	Generation Change	Total Rate Change

TOU-8-S-Rate LG (Below 2kV)

Energy Charge - \$/kWh

Summer Season

On-Peak

0.08210 0.50492 0.58702

0.07856 0.33871 0.41727

-4.3% -32.9% -28.9%

Mid-peak

0.08098 0.12833 0.20931

0.07765 0.12013 0.19778

-4.1% -6.4% -5.5%

Off-Peak

0.07606 0.08695 0.16301

0.07287 0.10014 0.17301

-4.2% 15.2% 6.1%

Winter Season

Mid-peak

0.08210 0.18678 0.26888

0.07856 0.19137 0.26993

-4.3% 2.5% 0.4%

Off-Peak

0.07629 0.10097 0.17726

0.07305 0.11114 0.18419

-4.2% 10.1% 3.9%

Super-Off-Peak

0.07344 0.05300 0.12644

0.07041 0.06863 0.13904

-4.1% 29.5% 10.0%

Customer Charge - \$/month

355.45 0.00 355.45

1,641.00 0.00 1,641.00

361.7% 361.7%

Facilities Related Demand

Demand Charge (Excess FRD) - \$/kW

13.58 0.00 13.58

12.61 0.00 12.61

-7.1% -7.1%

Standby (CRC) - \$/kW

18.75 0.00 18.75

15.93 0.00 15.93

-15.0% -15.0%

Time Related Demand Charge - \$/kW

Backup demand - Summer Season

On-Peak

13.19 28.70 41.89

12.20 14.83 27.03

-7.5% -48.3% -35.5%

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Winter Season

Mid-Peak

2.34 12.95 15.29

3.39 6.48 9.87

44.9% -50.0% -35.4%

Supplemental demand - Summer Season

On-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Winter Season

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Power Factor Adjustment - \$/kVA

0.52 0.00 0.52

0.60 0.00 0.60

15.4% 15.4%

TOU-8-S-B (Below 2kV) - GF

Energy Charge - \$/kWh

Summer Season

On-Peak

0.02916 0.10489 0.13405

0.03098 0.11598 0.14696

6.2% 10.6% 9.6%

Mid-peak

0.02916 0.09760 0.12676

0.03098 0.10796 0.13894

6.2% 10.6% 9.6%

Off-Peak

0.02916 0.09440 0.12356

0.03098 0.10438 0.13536

6.2% 10.6% 9.6%

Winter Season

Mid-peak

0.02916 0.12904 0.15820

0.03098 0.13782 0.16880

6.2% 6.8% 6.7%

Off-Peak

0.02916 0.07898 0.10814

0.03098 0.09180 0.12278

6.2% 16.2% 13.5%

Customer Charge - \$/month

355.45 0.00 355.45

1,641.00 0.00 1,641.00

361.7% 361.7%

Facilities Related Demand

Demand Charge (Excess FRD) - \$/kW

32.19 0.00 32.19

28.95 0.00 28.95

-10.1% -10.1%

Standby (CRC) - \$/kW

23.32 0.00 23.32

20.70 0.00 20.70

-11.2% -11.2%

Time Related Demand Charge - \$/kW

Backup demand - Summer Season

On-Peak

0.00 26.02 26.02

0.00 13.97 13.97

-46.3% -46.3%

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Supplemental demand - Summer Season

On-Peak

0.00 17.57 17.57

0.00 9.47 9.47

-46.1% -46.1%

Mid-Peak

0.00 5.77 5.77

0.00 3.11 3.11

-46.1% -46.1%

Power Factor Adjustment - \$/kVA

0.52 0.00 0.52

0.60 0.00 0.60

15.4% 15.4%

TOU-8-S-Rate A (Below 2kV) - GF

Energy Charge - \$/kWh

Summer Season

On-Peak

0.20059 0.30668 0.50727

0.17796 0.22441 0.40237

-11.3% -26.8% -20.7%

Mid-peak

0.10867 0.14672 0.25539

0.09943 0.13410 0.23353

-8.5% -8.6% -8.6%

Off-Peak

0.05539 0.09440 0.14979

0.05412 0.10438 0.15850

-2.3% 10.6% 5.8%

Winter Season

Mid-peak

0.04320 0.12904 0.17224

0.04403 0.13782 0.18185

1.9% 6.8% 5.6%

Off-Peak

0.03219 0.07898 0.11117

0.03371 0.09180 0.12551

4.7% 16.2% 12.9%

Customer Charge - \$/month

355.45 0.00 355.45

1,641.00 0.00 1,641.00

361.7% 361.7%

Facilities Related Demand

Demand Charge (Excess FRD) - \$/kW

20.02 0.00 20.02

18.27 0.00 18.27

-8.7% -8.7%

Standby (CRC) - \$/kW

23.32 0.00 23.32

20.70 0.00 20.70

-11.2% -11.2%

Time Related Demand Charge - \$/kW

Backup demand - Summer Season

On-Peak

0.00 26.02 26.02

0.00 13.97 13.97

-46.3% -46.3%

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Supplemental demand - Summer Season

On-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Power Factor Adjustment - \$/kVA

0.52 0.00 0.52

0.60 0.00 0.60

15.4% 15.4%

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TOU-8-S Rate D (From 2 kV to 50 kV)

Energy Charge - \$/kWh

Summer Season

On-Peak

0.03798 0.13478 0.17276

0.03874 0.14122 0.17996

2.0% 4.8% 4.2%

Mid-peak

0.03705 0.12315 0.16020

0.03791 0.11869 0.15660

2.3% -3.6% -2.2%

Off-Peak

0.03687 0.08326 0.12013

0.03775 0.09753 0.13528

2.4% 17.1% 12.6%

Winter Season

Mid-peak

0.03798 0.09632 0.13430

0.03874 0.11276 0.15150

2.0% 17.1% 12.8%

Off-Peak

0.03705 0.09712 0.13417

0.03791 0.10886 0.14677

2.3% 12.1% 9.4%

Super-Off-Peak

0.03647 0.05095 0.08742

0.03740 0.06721 0.10461

2.6% 31.9% 19.7%

Customer Charge - \$/month

367.81 0.00 367.81

202.50 0.00 202.50

-44.9% -44.9%

Facilities Related Demand

Demand Charge (Excess FRD) - \$/kW

21.42 0.00 21.42

21.06 0.00 21.06

-1.7% -1.7%

Standby (CRC) - \$/kW

10.94 0.00 10.94

11.29 0.00 11.29

3.2% 3.2%

Time Related Demand Charge - \$/kW

Backup demand - Summer Season

On-Peak

10.97 24.10 35.07

9.08 10.97 20.05

-17.2% -54.5% -42.8%

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Winter Season

Mid-Peak

1.70 4.18 5.88

2.52 5.76 8.28

48.2% 37.8% 40.8%

Supplemental demand - Summer Season

On-Peak

14.57 24.55 39.12

12.07 15.31 27.38

-17.2% -37.6% -30.0%

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Winter Season

Mid-Peak

2.63 9.19 11.82

3.33 7.78 11.11

26.6% -15.3% -6.0%

Power Factor Adjustment - \$/kVA

0.52 0.00 0.52

0.60 0.00 0.60

15.4% 15.4%

TOU-8-S-Rate LG (From 2 kV to 50 kV)

Energy Charge - \$/kWh

Summer Season

On-Peak

0.07477 0.46331 0.53808

0.07533 0.34787 0.42320

0.7% -24.9% -21.3%

Mid-peak

0.07384 0.12315 0.19699

0.07450 0.11869 0.19319

0.9% -3.6% -1.9%

Off-Peak

0.06958 0.08326 0.15284

0.07016 0.09753 0.16769

0.8% 17.1% 9.7%

Winter Season

Mid-peak

0.07477 0.18626 0.26103

0.07533 0.19090 0.26623

0.7% 2.5% 2.0%

Off-Peak

0.06976 0.09712 0.16688

0.07032 0.10886 0.17918

0.8% 12.1% 7.4%

Super-Off-Peak

0.06703 0.05095 0.11798

0.06764 0.06721 0.13485

0.9% 31.9% 14.3%

Customer Charge - \$/month

367.81 0.00 367.81

202.50 0.00 202.50

-44.9% -44.9%

Facilities Related Demand

Demand Charge (Excess FRD) - \$/kW

13.06 0.00 13.06

12.67 0.00 12.67

-3.0% -3.0%

Standby (CRC) - \$/kW

10.94 0.00 10.94

11.29 0.00 11.29

3.2% 3.2%

Time Related Demand Charge - \$/kW

Backup demand - Summer Season

On-Peak

10.97 24.10 35.07

9.08 10.97 20.05

-17.2% -54.5% -42.8%

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Winter Season

Mid-Peak

1.70 4.18 5.88

2.52 5.76 8.28

48.2% 37.8% 40.8%

Supplemental demand - Summer Season

On-Peak

0.00 0.00 0.00

0.00 0.00 0.00

0.00 0.00 0.00

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Winter Season

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

0.00 0.00 0.00

Power Factor Adjustment - \$/kVA

0.52 0.00 0.52

0.60 0.00 0.60

15.4% 15.4%

TOU-8-S-B (From 2 kV to 50 kV) - GF

Energy Charge - \$/kWh

Summer Season

On-Peak

0.02951 0.10077 0.13028

0.03140 0.11366 0.14506

6.40% 12.8% 11.3%

Mid-peak

0.02951 0.09334 0.12285

0.03140 0.10525 0.13665

6.40% 12.8% 11.2%

Off-Peak

0.02951 0.09069 0.12020

0.03140 0.10229 0.13369

6.40% 12.8% 11.2%

Winter Season

Mid-peak

0.02951 0.13446 0.16397

0.03140 0.14451 0.17591

6.40% 7.5% 7.3%

Off-Peak

0.02951 0.07766 0.10717

0.03140 0.09159 0.12299

6.40% 17.9% 14.8%

Customer Charge - \$/month

367.81 0.00 367.81

202.50 0.00 202.50

-44.9% -44.9%

Facilities Related Demand

Demand Charge (Excess FRD) - \$/kW

30.62 0.00 30.62

29.33 0.00 29.33

-4.2% -4.2%

Standby (CRC) - \$/kW

13.57 0.00 13.57

13.89 0.00 13.89

2.4% 2.4%

Time Related Demand Charge - \$/kW

Backup demand - Summer Season

On-Peak

0.00 22.59 22.59

0.00 9.86 9.86

-56.4% -56.4%

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Supplemental demand - Summer Season

On-Peak

0.00 17.28 17.28

0.00 10.71 10.71

-38.0% -38.0%

Mid-Peak

0.00 5.56 5.56

0.00 3.33 3.33

-40.1% -40.1%

Power Factor Adjustment - \$/kVA

0.52 0.00 0.52

0.60 0.00 0.60

15.4% 15.4%

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October 2023 Rates		
Delivery	Generation	Total Rate

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

Delivery Change	Generation Change	Total Rate Change

TOU-8-S-Rate A (From 2 kV to 50 kV) - GF

Energy Charge - \$/kWh

Summer Season

On-Peak

0.19041 0.29629 0.48670

0.18457 0.23786 0.42243

-3.1% -19.7% -13.2%

Mid-peak

0.09979 0.13762 0.23741

0.09809 0.13294 0.23103

-1.7% -3.4% -2.7%

Off-Peak

0.05015 0.09069 0.14084

0.05130 0.10229 0.15359

2.3% 12.8% 9.1%

Winter Season

Mid-peak

0.04235 0.13446 0.17681

0.04421 0.14451 0.18872

4.4% 7.5% 6.7%

Off-Peak

0.03188 0.07766 0.10954

0.03370 0.09159 0.12529

5.7% 17.9% 14.4%

Customer Charge - \$/month

367.81 0.00 367.81

202.50 0.00 202.50

-44.9% -44.9%

Facilities Related Demand

Demand Charge (Excess FRD) - \$/kW

19.33 0.00 19.33

18.62 0.00 18.62

-3.7% -3.7%

Standby (CRC) - \$/kW

13.57 0.00 13.57

13.89 0.00 13.89

2.4% 2.4%

Time Related Demand Charge - \$/kW

Backup demand - Summer Season

On-Peak

0.00 22.59 22.59

0.00 9.86 9.86

-56.4% -56.4%

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Supplemental demand - Summer Season

On-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Power Factor Adjustment - \$/kVA

0.52 0.00 0.52

0.60 0.00 0.60

15.4% 15.4%

TOU-8-S Rate D (Above 50 kV)

Energy Charge - \$/kWh

Summer Season

On-Peak

0.02328 0.12649 0.14977

0.02528 0.13555 0.16083

8.6% 7.2% 7.4%

Mid-peak

0.02328 0.11593 0.13921

0.02528 0.11431 0.13959

8.6% -1.4% 0.3%

Off-Peak

0.02328 0.07794 0.10122

0.02528 0.09448 0.11976

8.6% 21.2% 18.3%

Winter Season

Mid-peak

0.02328 0.09020 0.11348

0.02528 0.10956 0.13484

8.6% 21.5% 18.8%

Off-Peak

0.02328 0.09130 0.11458

0.02528 0.10615 0.13143

8.6% 16.3% 14.7%

Super-Off-Peak

0.02328 0.04787 0.07115

0.02528 0.06555 0.09083

8.6% 36.9% 27.7%

Customer Charge - \$/month

3,458.53 0.00 3,458.53

3,828.75 0.00 3,828.75

10.7% 10.7%

Facilities Related Demand

Demand Charge (Excess FRD) - \$/kW

10.63 0.00 10.63

11.48 0.00 11.48

8.0% 8.0%

Standby (CRC) - \$/kW

1.04 0.00 1.04

1.59 0.00 1.59

52.9% 52.9%

Time Related Demand Charge - \$/kW

Backup demand - Summer Season

On-Peak

1.66 10.28 11.94

3.06 9.75 12.81

84.3% -5.2% 7.3%

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Winter Season

Mid-Peak

0.21 4.99 5.20

0.49 5.05 5.54

133.3% 1.2% 6.5%

Supplemental demand - Summer Season

On-Peak

5.66 27.12 32.78

5.50 15.98 21.48

-2.8% -41.1% -34.5%

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Winter Season

Mid-Peak

0.65 8.77 9.42

0.79 9.05 9.84

21.5% 3.2% 4.5%

Power Factor Adjustment - \$/kVA

0.66 0.00 0.66

0.76 0.00 0.76

15.2% 15.2%

Voltage Discount, 220 kV and above

Facilities Related Demand (Excess FRD) - \$/kW

(4.52) 0.00 (4.52)

(6.23) 0.00 (6.23)

37.8% 37.8%

Time-Related Demand - \$/kW

Backup Summer On-Peak

(1.66) (0.10) (1.76)

(3.06) (0.10) (3.16)

84.3% 0.0% 79.5%

Backup Winter Mid-Peak

(1.66) (0.10) (1.76)

(0.49) (0.05) (0.54)

-70.5% -50.0% -69.3%

Supplemental Summer On-Peak

(5.08) (0.28) (5.36)

(5.50) (0.16) (5.66)

8.3% -42.9% 5.6%

Supplemental Winter Mid-Peak

(5.08) (0.28) (5.36)

(0.79) (0.09) (0.88)

-84.4% -67.9% -83.6%

Energy - \$/kWh

0.00000 (0.00082) (0.00082)

0.00000 (0.00098) (0.00098)

19.5% 19.5%

Standby (CRC) - \$/kW

(0.43) 0.00 (0.43)

(0.98) 0.00 (0.98)

127.9% 127.9%

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October 2023 Rates		
Delivery	Generation	Total Rate

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

Delivery Change	Generation Change	Total Rate Change

TOU-8-S-Rate LG (Above 50 kV)

Energy Charge - \$/kWh

Summer Season									
On-Peak	0.03251	0.45182	0.48433	0.03714	0.32678	0.36392	14.2%	-27.7%	-24.9%
Mid-peak	0.03251	0.11593	0.14844	0.03714	0.11431	0.15145	14.2%	-1.4%	2.0%
Off-Peak	0.03251	0.07794	0.11045	0.03714	0.09448	0.13162	14.2%	21.2%	19.2%
Winter Season									
Mid-peak	0.03251	0.16520	0.19771	0.03714	0.18605	0.22319	14.2%	12.6%	12.9%
Off-Peak	0.03251	0.09130	0.12381	0.03714	0.10615	0.14329	14.2%	16.3%	15.7%
Super-Off-Peak	0.03251	0.04787	0.08038	0.03714	0.06555	0.10269			
Customer Charge - \$/month	3,458.53	0.00	3,458.53	3,828.75	0.00	3,828.75	10.7%		10.7%
Facilities Related Demand									
Demand Charge (Excess FRD) - \$/kW	8.05	0.00	8.05	7.50	0.00	7.50	-6.8%		-6.8%
Standby (CRC) - \$/kW	1.04	0.00	1.04	1.59	0.00	1.59	52.9%		52.9%
Time Related Demand Charge - \$/kW									
Backup demand - Summer Season									
On-Peak	1.66	10.28	11.94	3.06	9.75	12.81	84.3%	-5.2%	7.3%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.21	4.99	5.20	0.49	5.05	5.54	133.3%	1.2%	6.5%
Supplemental demand - Summer Season									
On-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - \$/kVA	0.66	0.00	0.66	0.76	0.00	0.76	15.2%		15.2%
Voltage Discount, 220 kV and above									
Facilities Related Demand (Excess FRD) - \$/kW	(2.80)	0.00	(2.80)	(2.25)	0.00	(2.25)	-19.6%		-19.6%
Time-Related Demand - \$/kW									
Backup Summer On-Peak	(1.66)	(0.10)	(1.76)	(3.06)	(0.10)	(3.16)	84.3%	0.0%	79.5%
Backup Winter Mid-Peak	(1.66)	(0.10)	(1.76)	(0.49)	(0.05)	(0.54)	-70.5%	-50.0%	-69.3%
Supplemental Summer On-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Supplemental Winter Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Energy - \$/kWh	(0.00714)	(0.00109)	(0.00823)	(0.01186)	(0.00118)	(0.01304)	66.1%	8.3%	58.4%
Standby (CRC) - \$/kW	(0.43)	0.00	(0.43)	(0.98)	0.00	(0.98)	127.9%		127.9%

TOU-8-S-B (Above 50 kV) - GF

Energy Charge - \$/kWh

Summer Season									
On-Peak	0.02422	0.09440	0.11862	0.02622	0.10996	0.13618	8.3%	16.5%	14.8%
Mid-peak	0.02422	0.08715	0.11137	0.02622	0.10162	0.12784	8.3%	16.6%	14.8%
Off-Peak	0.02422	0.08496	0.10918	0.02622	0.09897	0.12519	8.3%	16.5%	14.7%
Winter Season									
Mid-peak	0.02422	0.12805	0.15227	0.02622	0.14774	0.17396	8.3%	15.4%	14.2%
Off-Peak	0.02422	0.07365	0.09787	0.02622	0.08966	0.11588	8.3%	21.7%	18.4%
Customer Charge - \$/month	3,458.53	0.00	3,458.53	3,828.75	0.00	3,828.75	10.7%		10.7%
Facilities Related Demand									
Demand Charge (Excess FRD) - \$/kW	12.33	0.00	12.33	13.21	0.00	13.21	7.1%		7.1%
Standby (CRC) - \$/kW	1.26	0.00	1.26	2.41	0.00	2.41	91.3%		91.3%
Time Related Demand Charge - \$/kW									
Backup demand - Summer Season									
On-Peak	0.00	8.18	8.18	0.00	8.60	8.60		5.1%	5.1%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Supplemental demand - Summer Season									
On-Peak	0.00	19.75	19.75	0.00	11.75	11.75		-40.5%	-40.5%
Mid-Peak	0.00	6.40	6.40	0.00	3.77	3.77		-41.1%	-41.1%
Power Factor Adjustment - \$/kVA	0.66	0.00	0.66	0.76	0.00	0.76	15.2%		15.2%
Voltage Discount, 220 kV and above									
Facilities Related Demand (Excess FRD) - \$/kW	(7.08)	0.00	(7.08)	(7.96)	0.00	(7.96)	12.4%		12.4%
Time-Related Demand - \$/kW									
Supplemental Summer on & Mid	0.00	(0.41)	(0.41)	0.00	(0.23)	(0.23)		-43.9%	-43.9%
Backup Summer on & Mid	0.00	(0.13)	(0.13)	0.00	(0.14)	(0.14)		7.7%	7.7%
Energy - \$/kWh	0.00000	(0.00082)	(0.00082)	0.00000	(0.00098)	(0.00098)		19.5%	19.5%
Standby (CRC) - \$/kW	(0.65)	0.00	(0.65)	(1.80)	0.00	(1.80)	176.9%		176.9%

			October 2023 Rates			Proposed 2025 GRC Rates					
			Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-S-Rate A (Above 50 kV) - GF											
Energy Charge - \$/kWh											
Summer Season											
On-Peak			0.08058	0.29414	0.37472	0.10002	0.22781	0.32783	24.1%	-22.6%	-12.5%
Mid-peak			0.04863	0.13105	0.17968	0.05807	0.12765	0.18572	19.4%	-2.6%	3.4%
Off-Peak			0.03073	0.08496	0.11569	0.03491	0.09897	0.13388	13.6%	16.5%	15.7%
Winter Season											
Mid-peak			0.02844	0.12805	0.15649	0.03201	0.14774	0.17975	12.6%	15.4%	14.9%
Off-Peak			0.02493	0.07365	0.09858	0.02717	0.08966	0.11683	9.0%	21.7%	18.5%
Customer Charge - \$/month			3,458.53	0.00	3,458.53	3,828.75	0.00	3,828.75	10.7%		10.7%
Facilities Related Demand											
Demand Charge (Excess FRD) - \$/kW			8.05	0.00	8.05	7.50	0.00	7.50	-6.8%		-6.8%
Standby (CRC) - \$/kW			1.26	0.00	1.26	2.41	0.00	2.41	91.3%		91.3%
Time Related Demand Charge - \$/kW											
Backup demand - Summer Season											
On-Peak			0.00	8.18	8.18	0.00	8.60	8.60		5.1%	5.1%
Mid-Peak			0.00	0.00		0.00	0.00	0.00			
Supplemental demand - Summer Season											
On-Peak			0.00	0.00		0.00	0.00	0.00			
Mid-Peak			0.00	0.00		0.00	0.00	0.00			
Power Factor Adjustment - \$/kVA			0.66	0.00	0.66	0.76	0.00	0.76	15.2%		15.2%
Voltage Discount, 220 kV and above											
Facilities Related Demand (Excess FRD) - \$/kW			(2.80)	0.00	(2.80)	(2.25)	0.00	(2.25)	-19.6%		-19.6%
Time-Related Demand - \$/kW											
Supplemental Summer on & Mid			0.00	0.00	0.00	0.00	0.00	0.00			
Backup Summer on & Mid			0.00	(0.13)	(0.13)	0.00	(0.14)	(0.14)		7.7%	7.7%
Energy - \$/kWh			(0.00829)	(0.00131)	(0.00960)	(0.01107)	(0.00126)	(0.01233)	33.5%	-3.8%	28.4%
Standby (CRC) - \$/kW			(0.65)	0.00	(0.65)	(1.80)	0.00	(1.80)	176.9%		176.9%

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Schedule-S-D (Less than 500 kW)

Energy Charge - \$/kWh/Meter/Month - see (OAT)

Customer Charge - \$/Meter/Month - see (OAT)

Standby (CRC) - \$/kW

TOU-GS-1 (Rate D)

October 2023 Rates									
	Delivery	Generation	Total Rate				Delivery Change	Generation Change	Total Rate Change
Voltage Discount, Capacity Reservation Demand - \$/kW									
	From 2 kV to 50 kV	(0.26)	0.00	(0.26)	(0.21)	0.00	(0.21)	-19.2%	-19.2%
	51 kV to 219 kV	(5.71)	0.00	(5.71)	(4.42)	0.00	(4.42)	-22.6%	-22.6%
	220 kV and Above	(12.99)	0.00	(12.99)	(10.35)	0.00	(10.35)	-20.3%	-20.3%
TOU-GS-1 (Rate LG)									
		9.60	0.00	9.60	4.81	0.00	4.81	-49.9%	-49.9%
Voltage Discount, Capacity Reservation Demand - \$/kW									
	From 2 kV to 50 kV	(0.12)	0.00	(0.12)	(0.10)	0.00	(0.10)	-16.7%	-16.7%
	51 kV to 219 kV	(2.67)	0.00	(2.67)	(2.05)	0.00	(2.05)	-23.2%	-23.2%
	220 kV and Above	(6.10)	0.00	(6.10)	(4.81)	0.00	(4.81)	-21.1%	-21.1%
TOU-GS-2 (Rate D)									
		18.95	0.00	18.95	15.82	0.00	15.82	-16.5%	-16.5%
Voltage Discount, Capacity Reservation Demand - \$/kW									
	From 2 kV to 50 kV	(0.29)	0.00	(0.29)	(0.23)	0.00	(0.23)	-20.7%	-20.7%
	51 kV to 219 kV	(6.22)	0.00	(6.22)	(4.70)	0.00	(4.70)	-24.4%	-24.4%
	220 kV and Above	(14.15)	0.00	(14.15)	(11.02)	0.00	(11.02)	-22.1%	-22.1%
TOU-GS-2 (Rate E)									
		12.44	0.00	12.44	11.59	0.00	11.59	-6.8%	-6.8%
Voltage Discount, Capacity Reservation Demand - \$/kW									
	From 2 kV to 50 kV	(0.15)	0.00	(0.15)	(0.14)	0.00	(0.14)	-6.7%	-6.7%
	51 kV to 219 kV	(3.36)	0.00	(3.36)	(2.90)	0.00	(2.90)	-13.7%	-13.7%
	220 kV and Above	(7.64)	0.00	(7.64)	(6.79)	0.00	(6.79)	-11.1%	-11.1%
TOU-GS-3 (Rate D)									
		19.06	0.00	19.06	15.93	0.00	15.93	-16.4%	-16.4%
Voltage Discount, Capacity Reservation Demand - \$/kW									
	From 2 kV to 50 kV	(0.27)	0.00	(0.27)	(0.27)	0.00	(0.27)	0.0%	0.0%
	51 kV to 219 kV	(5.88)	0.00	(5.88)	(5.53)	0.00	(5.53)	-6.0%	-6.0%
	220 kV and Above	(14.15)	0.00	(14.15)	(11.02)	0.00	(11.02)	-22.1%	-22.1%
TOU-GS-3 (Rate E)									
		12.34	0.00	12.34	11.86	0.00	11.86	-3.9%	-3.9%
Voltage Discount, Capacity Reservation Demand - \$/kW									
	From 2 kV to 50 kV	(0.14)	0.00	(0.14)	(0.17)	0.00	(0.17)	21.4%	21.4%
	51 kV to 219 kV	(3.08)	0.00	(3.08)	(3.49)	0.00	(3.49)	13.3%	13.3%
	220 kV and Above	(7.43)	0.00	(7.43)	(6.95)	0.00	(6.95)	-6.5%	-6.5%
TOU-PA-2 (Rate D4)									
		13.20	0.00	13.20	11.78	0.00	11.78	-10.8%	-10.8%
Voltage Discount, Capacity Reservation Demand - \$/kW									
	From 2 kV to 50 kV	(0.14)	0.00	(0.14)	(0.21)	0.00	(0.21)	50.0%	50.0%
	51 kV to 219 kV	(2.93)	0.00	(2.93)	(3.97)	0.00	(3.97)	35.5%	35.5%
	220 kV and Above	(10.74)	0.00	(10.74)	(9.32)	0.00	(9.32)	-13.2%	-13.2%
TOU-PA-2 (Rate E4)									
		11.37	0.00	11.37	9.95	0.00	9.95	-12.5%	-12.5%
Voltage Discount, Capacity Reservation Demand - \$/kW									
	From 2 kV to 50 kV	(0.12)	0.00	(0.12)	(0.17)	0.00	(0.17)	41.7%	41.7%
	51 kV to 219 kV	(2.42)	0.00	(2.42)	(3.19)	0.00	(3.19)	31.8%	31.8%
	220 kV and Above	(8.91)	0.00	(8.91)	(7.49)	0.00	(7.49)	-15.9%	-15.9%
TOU-PA-2 (Rate D5)									
		13.64	0.00	13.64	11.78	0.00	11.78	-13.6%	-13.6%
Voltage Discount, Capacity Reservation Demand - \$/kW									
	From 2 kV to 50 kV	(0.15)	0.00	(0.15)	(0.21)	0.00	(0.21)	40.0%	40.0%
	51 kV to 219 kV	(3.04)	0.00	(3.04)	(3.97)	0.00	(3.97)	30.6%	30.6%
	220 kV and Above	(11.18)	0.00	(11.18)	(9.32)	0.00	(9.32)	-16.6%	-16.6%
TOU-PA-2 (Rate E5)									
		11.37	0.00	11.37	9.95	0.00	9.95	-12.5%	-12.5%
Voltage Discount, Capacity Reservation Demand - \$/kW									
	From 2 kV to 50 kV	(0.12)	0.00	(0.12)	(0.17)	0.00	(0.17)	41.7%	41.7%
	51 kV to 219 kV	(2.42)	0.00	(2.42)	(3.19)	0.00	(3.19)	31.8%	31.8%
	220 kV and Above	(8.91)	0.00	(8.91)	(7.49)	0.00	(7.49)	-15.9%	-15.9%
TOU-PA-3 (Rate D4)									
		14.07	0.00	14.07	14.38	0.00	14.38	2.2%	2.2%
Voltage Discount, Capacity Reservation Demand - \$/kW									
	From 2 kV to 50 kV	(0.19)	0.00	(0.19)	(0.27)	0.00	(0.27)	42.1%	42.1%
	51 kV to 219 kV	(4.10)	0.00	(4.10)	(5.23)	0.00	(5.23)	27.6%	27.6%
	220 kV and Above	(10.71)	0.00	(10.71)	(11.02)	0.00	(11.02)	2.9%	2.9%
TOU-PA-3 (Rate E4)									
		11.94	0.00	11.94	13.71	0.00	13.71	14.8%	14.8%
Voltage Discount, Capacity Reservation Demand - \$/kW									
	From 2 kV to 50 kV	(0.16)	0.00	(0.16)	(0.25)	0.00	(0.25)	56.3%	56.3%
	51 kV to 219 kV	(3.28)	0.00	(3.28)	(4.91)	0.00	(4.91)	49.7%	49.7%
	220 kV and Above	(8.58)	0.00	(8.58)	(10.35)	0.00	(10.35)	20.6%	20.6%
TOU-PA-3 (Rate D5)									
		14.53	0.00	14.53	14.38	0.00	14.38	-1.0%	-1.0%
Voltage Discount, Capacity Reservation Demand - \$/kW									
	From 2 kV to 50 kV	(0.20)	0.00	(0.20)	(0.27)	0.00	(0.27)	35.0%	35.0%
	51 kV to 219 kV	(4.26)	0.00	(4.26)	(5.23)	0.00	(5.23)	22.8%	22.8%
	220 kV and Above	(11.17)	0.00	(11.17)	(11.02)	0.00	(11.02)	-1.3%	-1.3%

	October 2023 Rates			Proposed 2025 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-PA-3 (Rate E5)	11.94	0.00	11.94	13.71	0.00	13.71	14.8%		14.8%
Voltage Discount, Capacity Reservation Demand - \$/kW									
From 2 kV to 50 kV	(0.16)	0.00	(0.16)	(0.25)	0.00	(0.25)	56.3%		56.3%
51 kV to 219 kV	(3.28)	0.00	(3.28)	(4.91)	0.00	(4.91)	49.7%		49.7%
220 kV and Above	(8.58)	0.00	(8.58)	(10.35)	0.00	(10.35)	20.6%		20.6%
GS-1	16.49	0.00	16.49	10.35	0.00	10.35	-37.2%		-37.2%
Voltage Discount, Capacity Reservation Demand - \$/kW									
From 2 kV to 50 kV	(0.26)	0.00	(0.26)	(0.21)	0.00	(0.21)	-19.2%		-19.2%
51 kV to 219 kV	(5.71)	0.00	(5.71)	(4.42)	0.00	(4.42)	-22.6%		-22.6%
220 kV and Above	(12.99)	0.00	(12.99)	(10.35)	0.00	(10.35)	-20.3%		-20.3%
GS-2	18.95	0.00	18.95	15.82	0.00	15.82	-16.5%		-16.5%
Voltage Discount, Capacity Reservation Demand - \$/kW									
From 2 kV to 50 kV	(0.29)	0.00	(0.29)	(0.23)	0.00	(0.23)	-20.7%		-20.7%
51 kV to 219 kV	(6.22)	0.00	(6.22)	(4.70)	0.00	(4.70)	-24.4%		-24.4%
220 kV and Above	(14.15)	0.00	(14.15)	(11.02)	0.00	(11.02)	-22.1%		-22.1%
PA-1	13.20	0.00	13.20	11.78	0.00	11.78	-10.8%		-10.8%
Voltage Discount, Capacity Reservation Demand - \$/kW									
From 2 kV to 50 kV	(0.14)	0.00	(0.14)	(0.21)	0.00	(0.21)	50.0%		50.0%
51 kV to 219 kV	(2.93)	0.00	(2.93)	(3.97)	0.00	(3.97)	35.5%		35.5%
220 kV and Above	(10.74)	0.00	(10.74)	(9.32)	0.00	(9.32)	-13.2%		-13.2%
PA-2	13.20	0.00	13.20	11.78	0.00	11.78	-10.8%		-10.8%
Voltage Discount, Capacity Reservation Demand - \$/kW									
From 2 kV to 50 kV	(0.14)	0.00	(0.14)	(0.21)	0.00	(0.21)	50.0%		50.0%
51 kV to 219 kV	(2.93)	0.00	(2.93)	(3.97)	0.00	(3.97)	35.5%		35.5%
220 kV and Above	(10.74)	0.00	(10.74)	(9.32)	0.00	(9.32)	-13.2%		-13.2%
Facilities Related Demand Charge - see OAT									
Demand Charge - \$/kW applicable to metered maximum kW demand in excess Standby									
Generation Time-related demand charge - see OAT									
Power Factor Adjustment Charge - see OAT									
Schedule-S (Less than 500 kW) - GF									
Energy Charge - \$/kWh/Meter/Month - see (OAT)									
Customer Charge - \$/Meter/Month - see (OAT)									
Standby (CRC) - \$/kW									
TOU-GS-1 (Rate B)	20.75	0.00	20.75	14.01	0.00	14.01	-32.5%		-32.5%
Voltage Discount, Capacity Reservation Demand - \$/kW									
From 2 kV to 50 kV	(0.28)	0.00	(0.28)	(0.34)	0.00	(0.34)	21.4%		21.4%
51 kV to 219 kV	(5.58)	0.00	(5.58)	(6.05)	0.00	(6.05)	8.4%		8.4%
220 kV and Above	(17.25)	0.00	(17.25)	(14.01)	0.00	(14.01)	-18.8%		-18.8%
TOU-GS-1 (Rate C)	9.60	0.00	9.60	4.81	0.00	4.81	-49.9%		-49.9%
Voltage Discount, Capacity Reservation Demand - \$/kW									
From 2 kV to 50 kV	(0.12)	0.00	(0.12)	(0.10)	0.00	(0.10)	-16.7%		-16.7%
51 kV to 219 kV	(2.67)	0.00	(2.67)	(2.05)	0.00	(2.05)	-23.2%		-23.2%
220 kV and Above	(6.10)	0.00	(6.10)	(4.81)	0.00	(4.81)	-21.1%		-21.1%
TOU-GS-2 (Rate B)	23.62	0.00	23.62	20.59	0.00	20.59	-12.8%		-12.8%
Voltage Discount, Capacity Reservation Demand - \$/kW									
From 2 kV to 50 kV	(0.46)	0.00	(0.46)	(0.41)	0.00	(0.41)	-10.9%		-10.9%
51 kV to 219 kV	(9.49)	0.00	(9.49)	(7.19)	0.00	(7.19)	-24.2%		-24.2%
220 kV and Above	(18.82)	0.00	(18.82)	(15.79)	0.00	(15.79)	-16.1%		-16.1%
TOU-GS-2 (Rate R)	18.12	0.00	18.12	16.68	0.00	16.68	-7.9%		-7.9%
Voltage Discount, Capacity Reservation Demand - \$/kW									
From 2 kV to 50 kV	(0.33)	0.00	(0.33)	(0.31)	0.00	(0.31)	-6.1%		-6.1%
51 kV to 219 kV	(6.73)	0.00	(6.73)	(5.41)	0.00	(5.41)	-19.6%		-19.6%
220 kV and Above	(13.32)	0.00	(13.32)	(11.88)	0.00	(11.88)	-10.8%		-10.8%
TOU-GS-3 (Rate B)	23.73	0.00	23.73	20.70	0.00	20.70	-12.8%		-12.8%
Voltage Discount, Capacity Reservation Demand - \$/kW									
From 2 kV to 50 kV	(0.44)	0.00	(0.44)	(0.46)	0.00	(0.46)	4.5%		4.5%
51 kV to 219 kV	(8.94)	0.00	(8.94)	(8.00)	0.00	(8.00)	-10.5%		-10.5%
220 kV and Above	(18.82)	0.00	(18.82)	(15.79)	0.00	(15.79)	-16.1%		-16.1%
TOU-GS-3 (Rate R)	18.23	0.00	18.23	17.39	0.00	17.39	-4.6%		-4.6%
Voltage Discount, Capacity Reservation Demand - \$/kW									
From 2 kV to 50 kV	(0.31)	0.00	(0.31)	(0.37)	0.00	(0.37)	19.4%		19.4%
51 kV to 219 kV	(6.33)	0.00	(6.33)	(6.32)	0.00	(6.32)	-0.2%		-0.2%
220 kV and Above	(13.32)	0.00	(13.32)	(12.48)	0.00	(12.48)	-6.3%		-6.3%
TOU-PA-2 (Rate B)	17.22	0.00	17.22	15.84	0.00	15.84	-8.0%		-8.0%
Voltage Discount, Capacity Reservation Demand - \$/kW									
From 2 kV to 50 kV	(0.20)	0.00	(0.20)	(0.31)	0.00	(0.31)	55.0%		55.0%
51 kV to 219 kV	(4.22)	0.00	(4.22)	(5.33)	0.00	(5.33)	26.3%		26.3%
220 kV and Above	(14.76)	0.00	(14.76)	(13.38)	0.00	(13.38)	-9.3%		-9.3%

	October 2023 Rates			Proposed 2025 GRC Rates			Delivery Change	Generation Change	Total Rate Change
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate			
TOU-PA-2 (Rate A)	11.37	0.00	11.37	9.95	0.00	9.95	-12.5%		-12.5%
Voltage Discount, Capacity Reservation Demand - \$/kW									
From 2 kV to 50 kV	(0.13)	0.00	(0.13)	(0.17)	0.00	(0.17)	30.8%		30.8%
51 kV to 219 kV	(2.54)	0.00	(2.54)	(2.98)	0.00	(2.98)	17.3%		17.3%
220 kV and Above	(8.91)	0.00	(8.91)	(7.49)	0.00	(7.49)	-15.9%		-15.9%
TOU-PA-3 (Rate B)	18.64	0.00	18.64	19.15	0.00	19.15	2.7%		2.7%
Voltage Discount, Capacity Reservation Demand - \$/kW									
From 2 kV to 50 kV	(0.28)	0.00	(0.28)	(0.38)	0.00	(0.38)	35.7%		35.7%
51 kV to 219 kV	(5.60)	0.00	(5.60)	(6.84)	0.00	(6.84)	22.1%		22.1%
220 kV and Above	(15.28)	0.00	(15.28)	(15.79)	0.00	(15.79)	3.3%		3.3%
TOU-PA-3 (Rate A)	11.94	0.00	11.94	13.71	0.00	13.71	14.8%		14.8%
Voltage Discount, Capacity Reservation Demand - \$/kW									
From 2 kV to 50 kV	(0.16)	0.00	(0.16)	(0.25)	0.00	(0.25)	56.3%		56.3%
51 kV to 219 kV	(3.15)	0.00	(3.15)	(4.48)	0.00	(4.48)	42.2%		42.2%
220 kV and Above	(8.58)	0.00	(8.58)	(10.35)	0.00	(10.35)	20.6%		20.6%
Facilities Related Demand Charge - see OAT									
Demand Charge - \$/kW applicable to metered maximum kW demand in excess Standby									
Generation Time-related demand charge - see OAT									
Power Factor Adjustment Charge - see OAT									
TOU-8-S-RTP (Below 2kV)									
Energy Charge - \$/kWh									
Summer Season									
On-Peak	0.03957 Variable*	Variable*		0.03900 Variable*	Variable*		-1.4%		
Mid-peak	0.03845 Variable*	Variable*		0.03809 Variable*	Variable*		-0.9%		
Off-Peak	0.03822 Variable*	Variable*		0.03791 Variable*	Variable*		-0.8%		
Winter Season									
Mid-peak	0.03957 Variable*	Variable*		0.03900 Variable*	Variable*		-1.4%		
Off-Peak	0.03845 Variable*	Variable*		0.03809 Variable*	Variable*		-0.9%		
Super-Off-Peak	0.03780 Variable*	Variable*		0.03757 Variable*	Variable*		-0.6%		
Customer Charge - \$/month	355.45	0.00	355.45	1,641.00	0.00	1,641.00	361.7%		361.7%
Facilities Related Demand Charge - \$/kW									
Demand Charge (Excess FRD) - \$/kW	21.97	0.00	21.97	20.73	0.00	20.73	-5.6%		-5.6%
Standby (CRC) - \$/kW	18.75	0.00	18.75	15.93	0.00	15.93	-15.0%		-15.0%
Time Related Demand Charge - \$/kW									
Backup demand									
Summer Season									
On-Peak	13.19	0.00	13.19	12.20	0.00	12.20	-7.5%		-7.5%
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Winter Season									
Mid-Peak	2.34	0.00	2.34	3.39	0.00	3.39	44.9%		44.9%
Supplemental demand Summer Season									
On-Peak	16.16	0.00	16.16	11.79	0.00	11.79	-27.0%		-27.0%
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Winter Season									
Mid-Peak	2.77	0.00	2.77	3.19	0.00	3.19	15.2%		15.2%
Power Factor Adjustment - \$/kVA	0.52	0.00	0.52	0.60	0.00	0.60	15.4%		15.4%
TOU-8-S-RTP (From 2 kV to 50 kV)									
Energy Charge - \$/kWh									
Summer Season									
On-Peak	0.03798 Variable*	Variable*		0.03874 Variable*	Variable*		2.0%		
Mid-peak	0.03705 Variable*	Variable*		0.03791 Variable*	Variable*		2.3%		
Off-Peak	0.03687 Variable*	Variable*		0.03775 Variable*	Variable*		2.4%		
Winter Season									
Mid-peak	0.03798 Variable*	Variable*		0.03874 Variable*	Variable*		2.0%		
Off-Peak	0.03705 Variable*	Variable*		0.03791 Variable*	Variable*		2.3%		
Super-Off-Peak	0.03647 Variable*	Variable*		0.03740 Variable*	Variable*		2.6%		
Customer Charge - \$/month	367.81	0.00	367.81	202.50	0.00	202.50	-44.9%		-44.9%
Facilities Related Demand Charge - \$/kW									
Demand Charge (Excess FRD) - \$/kW	21.42	0.00	21.42	21.06	0.00	21.06	-1.7%		-1.7%
Standby (CRC) - \$/kW	10.94	0.00	10.94	11.29	0.00	11.29			
Time Related Demand Charge - \$/kW									
Backup demand									
Summer Season									
On-Peak	10.97	0.00	10.97	9.08	0.00	9.08	-17.2%		-17.2%
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Winter Season									
Mid-Peak	1.70	0.00	1.70	2.52	0.00	2.52	48.2%		48.2%
Supplemental demand Summer Season									
On-Peak	14.57	0.00	14.57	12.07	0.00	12.07	-17.2%		-17.2%
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Winter Season									
Mid-Peak	2.63	0.00	2.63	3.33	0.00	3.33	26.6%		26.6%
Power Factor Adjustment - \$/kVA	0.52	0.00	0.52	0.60	0.00	0.60	15.4%		15.4%

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TOU-8-RTP (Above 50 kV)

Energy Charge - \$/kWh

Summer Season

On-Peak

Mid-Peak

Off-Peak

Winter Season

Mid-Peak

Off-Peak

Super-Off-Peak

Customer Charge - \$/month

Facilities Related Demand Charge - \$/kW

Demand Charge (Excess FRD) - \$/kW

Standby (CRC) - \$/kW

Time Related Demand Charge - \$/kW

Backup demand

Summer Season

On-Peak

Mid-Peak

Winter Season

Mid-Peak

Supplemental demand Summer Season

On-Peak

Mid-Peak

Winter Season

Mid-Peak

Power Factor Adjustment - \$/kVA

Voltage Discount, 220 kV and above

Facilities Related Demand (Excess FRD) - \$/kW

Time-Related Demand - \$/kW

Backup Summer On-Peak

Backup Winter Mid-Peak

Supplemental Summer On-Peak

Supplemental Winter Mid-Peak

Energy - \$/kWh

Standby (CRC) - \$/kW

TOU-PA-2-D-RTP

Energy Charge - \$/kWh

Summer Season

On-Peak

Mid-Peak

Off-Peak

Winter Season

Mid-Peak

Off-Peak

Super-Off-Peak

Customer Charge - \$/month

Facilities Related

Demand Charge - \$/kW

Time Related Demand Charge - \$/kW

Summer Season

On-Peak

Mid-Peak

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV

From 51 kV to 219 kV

220 kV and above

Voltage Discount, Time-Related Demand - \$/kW

From 2 kV to 50 kV

From 51 kV to 219 kV

220 kV and above

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV

From 51 kV to 219 kV

220 kV and above

California Climate Credit - \$/kWh/Meter/Month

October 2023 Rates		
Delivery	Generation	Total Rate

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

Delivery Change	Generation Change	Total Rate Change
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0.02328 Variable* Variable*

0.02328 Variable* Variable*

0.02328 Variable* Variable*

0.02328 Variable* Variable*

0.02328 Variable* Variable*

0.02328 Variable* Variable*

3,458.53 0.00 3,458.53

10.63 0.00 10.63

1.04 0.00 1.04

3,458.53 0.00 3,458.53

1.66 0.00 1.66

0.00 0.00 0.00

0.21 0.00 0.21

5.66 0.00 5.66

0.00 0.00 0.00

0.65 0.00 0.65

0.66 0.00 0.66

(4.52) 0.00 (4.52)

(1.66) 0.00 (1.66)

(1.66) 0.00 (1.66)

(5.08) 0.00 (5.08)

(5.08) 0.00 (5.08)

0.00000 (0.00109) (0.00109)

(0.43) 0.00 (0.43)

0.02528 Variable* Variable*

0.02528 Variable* Variable*

0.02528 Variable* Variable*

0.02528 Variable* Variable*

0.02528 Variable* Variable*

0.02528 Variable* Variable*

3,828.75 0.00 3,828.75

11.48 0.00 11.48

1.59 0.00 1.59

3,828.75 0.00 3,828.75

3.06 0.00 3.06

0.00 0.00 0.00

0.49 0.00 0.49

5.50 0.00 5.50

0.00 0.00 0.00

0.79 0.00 0.79

0.76 0.00 0.76

(6.23) 0.00 (6.23)

(3.06) 0.00 (3.06)

(0.49) 0.00 (0.49)

(5.50) 0.00 (5.50)

(0.79) 0.00 (0.79)

0.00000 (0.00118) (0.00118)

(0.98) 0.00 (0.98)

8.6%

8.6%

8.6%

8.6%

8.6%

8.6%

10.7%

8.0%

52.9%

10.7%

84.3%

0.00

0.49

-2.8%

0.00

0.79

15.2%

37.8%

84.3%

-70.5%

8.3%

-84.4%

8.3%

127.9%

8.3%

127.9%

			October 2023 Rates			Proposed 2025 GRC Rates					
			Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
PA-1											
Energy Charge - \$/kWh			0.07981	0.13585	0.21566	0.07395	0.12911	0.20306	-7.3%	-5.0%	-5.8%
Customer Charge - \$/month			72.69	0.00	72.69	32.75	0.00	32.75	-54.9%		-54.9%
Service Charge - \$/hp			6.12	0.00	6.12	5.32	0.00	5.32	-13.1%		-13.1%
Wind Machine Credit- \$/hp			0.00	(6.06)	(6.06)	0.00	(5.12)	(5.12)		-15.5%	-15.5%
Voltage Discount, Energy - \$/kWh											
From 2 kV to 50 kV			(0.00108)	(0.00182)	(0.00290)	(0.00145)	(0.00170)	(0.00315)	34.3%	-6.6%	8.6%
From 51 kV to 219 kV			(0.02339)	(0.00398)	(0.02737)	(0.02961)	(0.00367)	(0.03328)	26.6%	-7.8%	21.6%
220 kV and above			(0.04712)	(0.00401)	(0.05113)	(0.04030)	(0.00371)	(0.04401)	-14.5%	-7.5%	-13.9%
Voltage Discount, Connected Load - \$/Hp											
From 2 kV to 50 kV			(0.04)	0.00	(0.04)	(0.03)	0.00	(0.03)	-25.0%		-25.0%
From 51 kV to 219 kV			(1.82)	0.00	(1.82)	(1.48)	0.00	(1.48)	-18.7%		-18.7%
220 kV and above			(1.86)	0.00	(1.86)	(1.51)	0.00	(1.51)	-18.8%		-18.8%
PA-2											
Energy Charge - \$/kWh											
Summer			0.06097	0.13570	0.19667	0.06814	0.12084	0.18898	11.8%	-11.0%	-3.9%
Winter			0.04667	0.11324	0.15991	0.03740	0.11828	0.15568	-19.9%	4.5%	-2.6%
Customer Charge - \$/month			72.69	0.00	72.69	32.75	0.00	32.75	-54.9%		-54.9%
Facilities Related											
Demand Charge - \$/kW			13.42	0.00	13.42	11.78	0.00	11.78	-12.2%		-12.2%
Time Related Demand Charge - \$/kW											
Summer Season			0.00	5.71	5.71	0.00	5.58	5.58		-2.3%	-2.3%
Winter Season			0.00	0.00	0.00	0.00	0.00	0.00			
TOU Rate Meter Charge - \$/month											
TOU-RTEM			0.00	0.00	0.00	0.00	0.00	0.00			
Voltage Discount, Facilities Related Demand - \$/kW											
From 2 kV to 50 kV			(0.14)	0.00	(0.14)	(0.21)	0.00	(0.21)	50.0%		50.0%
From 51 kV to 219 kV			(2.99)	0.00	(2.99)	(3.97)	0.00	(3.97)	32.8%		32.8%
220 kV and above			(10.96)	0.00	(10.96)	(9.32)	0.00	(9.32)	-15.0%		-15.0%
Voltage Discount, Time-Related Demand - \$/kW											
From 2 kV to 50 kV			0.00	(0.13)	(0.13)	0.00	(0.12)	(0.12)		-7.7%	-7.7%
From 51 kV to 219 kV			0.00	(0.29)	(0.29)	0.00	(0.29)	(0.29)		0.0%	0.0%
220 kV and above			0.00	(0.29)	(0.29)	0.00	(0.29)	(0.29)		0.0%	0.0%
Voltage Discount, Energy - \$/kWh											
From 2 kV to 50 kV			(0.00036)	(0.00166)	(0.00202)	(0.00043)	(0.00157)	(0.00200)	19.4%	-5.4%	-1.0%
From 51 kV to 219 kV			(0.00660)	(0.00365)	(0.01025)	(0.00602)	(0.00339)	(0.00941)	-8.8%	-7.1%	-8.2%
220 kV and above			(0.02066)	(0.00368)	(0.02434)	(0.01791)	(0.00343)	(0.02134)	-13.3%	-6.8%	-12.3%
TOU-PA-2-E4											
Energy Charge - \$/kWh											
Summer Season											
On-Peak			0.10385	0.52211	0.62596	0.13148	0.36047	0.49195	26.6%	-31.0%	-21.4%
Mid-peak			0.10385	0.14144	0.24529	0.09692	0.12423	0.22115	-6.7%	-12.2%	-9.8%
Off-Peak			0.05385	0.09361	0.14746	0.05917	0.10061	0.15978	9.9%	7.5%	8.4%
Winter Season											
Mid-peak			0.06582	0.14064	0.20646	0.05285	0.14729	0.20014	-19.7%	4.7%	-3.1%
Off-Peak			0.05905	0.11192	0.17097	0.04893	0.11721	0.16614	-17.1%	4.7%	-2.8%
Super-Off-Peak			0.05520	0.09557	0.15077	0.04670	0.10009	0.14679	-15.4%	4.7%	-2.6%
Customer Charge - \$/month			72.69	0.00	72.69	32.75	0.00	32.75	-54.9%		-54.9%
Facilities Related											
Demand Charge - \$/kW			11.72	0.00	11.72	9.95	0.00	9.95	-15.1%		-15.1%
Wind Machine Credit- \$/kW			0.00	(10.16)	(10.16)	0.00	(8.84)	(8.84)		-13.0%	-13.0%
Voltage Discount, Energy - \$/kWh											
From 2 kV to 50 kV			(0.00045)	(0.00209)	(0.00254)	(0.00061)	(0.00188)	(0.00249)	35.6%	-10.0%	-2.0%
From 51 kV to 219 kV			(0.00870)	(0.00467)	(0.01337)	(0.00930)	(0.00415)	(0.01345)	6.9%	-11.1%	0.6%
220 kV and above			(0.02844)	(0.00469)	(0.03313)	(0.02554)	(0.00420)	(0.02974)	-10.2%	-10.4%	-10.2%
Voltage Discount, Facilities Related Demand - \$/kW											
From 2 kV to 50 kV			(0.12)	0.00	(0.12)	(0.17)	0.00	(0.17)	41.7%		41.7%
From 51 kV to 219 kV			(2.53)	0.00	(2.53)	(3.19)	0.00	(3.19)	26.1%		26.1%
220 kV and above			(9.26)	0.00	(9.26)	(7.49)	0.00	(7.49)	-19.1%		-19.1%
California Climate Credit - \$/kWh/Meter/Month			(71.00000)	0.00000	(71.00000)	(71.00000)	0.00000	(71.00000)	0.0%		0.0%

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October 2023 Rates		
Delivery	Generation	Total Rate

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

Delivery Change	Generation Change	Total Rate Change

TOU-PA-2-E5

Energy Charge - \$/kWh

Summer Season

On-Peak

0.11406 0.86879 0.98285

0.10322 0.48537 0.58859

-9.5% -44.1% -40.1%

Mid-peak

0.11406 0.29146 0.40552

0.10322 0.26985 0.37307

-9.5% -7.4% -8.0%

Off-Peak

0.05774 0.08772 0.14546

0.05661 0.10084 0.15745

-2.0% 15.0% 8.2%

Winter Season

Mid-peak

0.06594 0.14127 0.20721

0.06389 0.15167 0.21556

-3.1% 7.4% 4.0%

Off-Peak

0.05915 0.11242 0.17157

0.05771 0.12070 0.17841

-2.4% 7.4% 4.0%

Super-Off-Peak

0.05529 0.09600 0.15129

0.05420 0.10307 0.15727

Customer Charge - \$/month

72.69 0.00 72.69

32.75 0.00 32.75

-54.9% -54.9%

Facilities Related

Demand Charge - \$/kW

11.72 0.00 11.72

9.95 0.00 9.95

-15.1% -15.1%

Wind Machine Credit- \$/kW

0.00 (10.16) (10.16)

0.00 (8.84) (8.84)

-13.0% -13.0%

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV

(0.00045) (0.00209) (0.00254)

(0.00088) (0.00185) (0.00273)

95.6% -11.5% 7.5%

From 51 kV to 219 kV

(0.00870) (0.00467) (0.01337)

(0.01411) (0.00415) (0.01826)

62.2% -11.1% 36.6%

220 kV and above

(0.02844) (0.00469) (0.03313)

(0.03749) (0.00429) (0.04178)

31.8% -8.5% 26.1%

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV

(0.12) 0.00 (0.12)

(0.17) 0.00 (0.17)

41.7% 41.7%

From 51 kV to 219 kV

(2.53) 0.00 (2.53)

(3.19) 0.00 (3.19)

26.1% 26.1%

220 kV and above

(9.26) 0.00 (9.26)

(7.49) 0.00 (7.49)

-19.1% -19.1%

California Climate Credit - \$/kWh/Meter/Month

(71.00) - (71.00)

(71.00) - (71.00)

0.0% 0.0%

TOU-PA-2-D4

Energy Charge - \$/kWh

Summer Season

On-Peak

0.07025 0.15514 0.22539

0.10350 0.14808 0.25158

47.3% -4.6% 11.6%

Mid-peak

0.07025 0.14144 0.21169

0.06894 0.12423 0.19317

-1.9% -12.2% -8.7%

Off-Peak

0.04386 0.09361 0.13747

0.04975 0.10061 0.15036

13.4% 7.5% 9.4%

Winter Season

Mid-peak

0.07025 0.12149 0.19174

0.03899 0.12593 0.16492

-44.5% 3.7% -14.0%

Off-Peak

0.04386 0.09667 0.14053

0.03495 0.10022 0.13517

-20.3% 3.7% -3.8%

Super-Off-Peak

0.03727 0.08256 0.11983

0.03948 0.08558 0.12506

5.9% 3.7% 4.4%

Customer Charge - \$/month

72.69 0.00 72.69

32.75 0.00 32.75

-54.9% -54.9%

Facilities Related

Demand Charge - \$/kW

13.42 0.00 13.42

11.78 0.00 11.78

-12.2% -12.2%

Time Related Demand Charge - \$/kW

Summer Season

On-Peak

3.47 15.71 19.18

3.13 10.52 13.65

-9.8% -33.0% -28.8%

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Winter Season

Mid-Peak

0.00 3.55 3.55

0.00 4.26 4.26

20.0% 20.0%

Wind Machine Credit- \$/kW

0.00 (10.16) (10.16)

0.00 (8.84) (8.84)

-13.0% -13.0%

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV

(0.14) 0.00 (0.14)

(0.21) 0.00 (0.21)

50.0% 50.0%

From 51 kV to 219 kV

(2.99) 0.00 (2.99)

(3.97) 0.00 (3.97)

32.8% 32.8%

220 kV and above

(10.96) 0.00 (10.96)

(9.32) 0.00 (9.32)

-15.0% -15.0%

Voltage Discount, Time-Related Demand - \$/kW

Summer

From 2 kV to 50 kV

(0.06) (0.21) (0.27)

(0.08) (0.23) (0.31)

33.3% 9.5% 14.8%

From 51 kV to 219 kV

(1.11) (0.48) (1.59)

(1.05) (0.54) (1.59)

-5.4% 12.5% 0.0%

220 kV and above

(3.47) (0.48) (3.95)

(3.13) (0.55) (3.68)

-9.8% 14.6% -6.8%

Winter

From 2 kV to 50 kV

0.00 (0.11) (0.11)

From 51 kV to 219 kV

0.00 (0.25) (0.25)

220 kV and above

0.00 (0.25) (0.25)

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV

(0.00026) (0.00130) (0.00156)

(0.00032) (0.00134) (0.00166)

23.1% 3.1% 6.4%

From 51 kV to 219 kV

(0.00482) (0.00286) (0.00768)

(0.00450) (0.00290) (0.00740)

-6.6% 1.4% -3.6%

220 kV and above

(0.01508) (0.00288) (0.01796)

(0.01339) (0.00293) (0.01632)

-11.2% 1.7% -9.1%

California Climate Credit - \$/kWh/Meter/Month

(71.00) - (71.00)

(71.00) - (71.00)

0.0% 0.0%

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TOU-PA-2-D5

Energy Charge - \$/kWh

	Summer Season									
	On-Peak	0.07338	0.30900	0.38238	0.07034	0.31568	0.38602	-4.1%	2.2%	1.0%
	Mid-peak	0.07338	0.29146	0.36484	0.07034	0.26985	0.34019	-4.1%	-7.4%	-6.8%
	Off-Peak	0.04521	0.08772	0.13293	0.04703	0.10084	0.14787	4.0%	15.0%	11.2%
	Winter Season									
	Mid-peak	0.07338	0.12987	0.20325	0.07034	0.14097	0.21131	-4.1%	8.5%	4.0%
	Off-Peak	0.04521	0.10335	0.14856	0.04703	0.11218	0.15921	4.0%	8.5%	7.2%
	Super-Off-Peak	0.03804	0.08825	0.12629	0.04098	0.09579	0.13677	7.7%	8.5%	8.3%
Customer Charge - \$/month		72.69	0.00	72.69	32.75	0.00	32.75	-54.9%		-54.9%
Facilities Related										
	Demand Charge - \$/kW	13.96	0.00	13.96	11.78	0.00	11.78	-15.6%		-15.6%
Time Related Demand Charge - \$/kW										
	Summer Season									
	On-Peak	2.34	15.04	17.38	2.33	5.28	7.61	-0.4%	-64.9%	-56.2%
	Mid-Peak	0.00	0.00		0.00	0.00	0.00			
	Winter Season									
	Mid-Peak	0.00	2.23	2.23	0.00	2.23	2.23		0.0%	0.0%
Wind Machine Credit- \$/kW		0.00	(10.16)	(10.16)	0.00	(8.84)	(8.84)		-13.0%	-13.0%
Voltage Discount, Facilities Related Demand - \$/kW										
	From 2 kV to 50 kV	(0.15)	0.00	(0.15)	(0.21)	0.00	(0.21)	40.0%		40.0%
	From 51 kV to 219 kV	(3.14)	0.00	(3.14)	(3.97)	0.00	(3.97)	26.4%		26.4%
	220 kV and above	(11.50)	0.00	(11.50)	(9.32)	0.00	(9.32)	-19.0%		-19.0%
Voltage Discount, Time-Related Demand - \$/kW										
	Summer									
	From 2 kV to 50 kV	(0.04)	(0.19)	(0.23)	(0.06)	(0.12)	(0.18)	50.0%	-36.8%	-21.7%
	From 51 kV to 219 kV	(0.75)	(0.43)	(1.18)	(0.78)	(0.27)	(1.05)	4.0%	-37.2%	-11.0%
	220 kV and above	(2.34)	(0.43)	(2.77)	(2.33)	(0.28)	(2.61)	-0.4%	-34.9%	-5.8%
	Winter									
	From 2 kV to 50 kV				0.00	(0.06)	(0.06)			
	From 51 kV to 219 kV				0.00	(0.13)	(0.13)			
	220 kV and above				0.00	(0.13)	(0.13)			
Voltage Discount, Energy - \$/kWh										
	From 2 kV to 50 kV	(0.00025)	(0.00138)	(0.00163)	(0.00035)	(0.00159)	(0.00194)	40.0%	15.2%	19.0%
	From 51 kV to 219 kV	(0.00463)	(0.00305)	(0.00768)	(0.00484)	(0.00348)	(0.00832)	4.5%	14.1%	8.3%
	220 kV and above	(0.01408)	(0.00307)	(0.01715)	(0.01439)	(0.00351)	(0.01790)	2.2%	14.3%	4.4%
California Climate Credit - \$/kWh/Meter/Month		(71.00)	-	(71.00)	(71.00)	-	(71.00)	0.0%		0.0%

TOU-PA-2-CPP

Energy Charge - \$/kWh

Summer Season									
On-Peak	0.07025	0.15514	0.22539	0.10350	0.14808	0.25158	47.3%	-4.6%	11.6%
Mid-peak	0.07025	0.14144	0.21169	0.06894	0.12423	0.19317	-1.9%	-12.2%	-8.7%
Off-Peak	0.04386	0.09361	0.13747	0.04975	0.10061	0.15036	13.4%	7.5%	9.4%
Winter Season									
Mid-peak	0.07025	0.12149	0.19174	0.03899	0.12593	0.16492	-44.5%	3.7%	-14.0%
Off-Peak	0.04386	0.09667	0.14053	0.03495	0.10022	0.13517	-20.3%	3.7%	-3.8%
Super-Off-Peak	0.03727	0.08256	0.11983	0.03948	0.08558	0.12506	5.9%	3.7%	4.4%
Customer Charge - \$/month	72.69	0.00	72.69	32.75	0.00	32.75	-54.9%		-54.9%
Facilities Related									
Demand Charge - \$/kW	13.42	0.00	13.42	11.78	0.00	11.78	-12.2%		-12.2%
Time Related Demand Charge - \$/kW									
Summer Season									
On-Peak	3.47	15.71	19.18	3.13	10.52	13.65	-9.8%	-33.0%	-28.8%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.00	3.55	3.55	0.00	4.26	4.26		20.0%	20.0%
Wind Machine Credit- \$/kW	0.00	(10.16)	(10.16)	0.00	(8.84)	(8.84)		-13.0%	-13.0%
Voltage Discount, Facilities Related Demand - \$/kW									
From 2 kV to 50 kV	(0.14)	0.00	(0.14)	(0.21)	0.00	(0.21)	50.0%		50.0%
Above 50 kV but below 220 kV	(2.99)	0.00	(2.99)	(3.97)	0.00	(3.97)	32.8%		32.8%
At 220 kV	(10.96)	0.00	(10.96)	(9.32)	0.00	(9.32)	-15.0%		-15.0%
Voltage Discount, Time-Related Demand - \$/kW									
Summer									
From 2 kV to 50 kV	(0.06)	(0.21)	(0.27)	(0.08)	(0.23)	(0.31)	33.3%	9.5%	14.8%
Above 50 kV but below 220 kV	(1.11)	(0.48)	(1.59)	(1.05)	(0.54)	(1.59)	-5.4%	12.5%	0.0%
At 220 kV	(3.47)	(0.48)	(3.95)	(3.13)	(0.55)	(3.68)	-9.8%	14.6%	-6.8%
Winter									
From 2 kV to 50 kV		(0.21)	(0.21)	0.00	(0.11)	(0.11)		-47.6%	-47.6%
Above 50 kV but below 220 kV		(0.48)	(0.48)	0.00	(0.25)	(0.25)		-47.9%	-47.9%
At 220 kV		(0.48)	(0.48)	0.00	(0.25)	(0.25)		-47.9%	-47.9%
Voltage Discount, Energy - \$/kWh									
From 2 kV to 50 kV	(0.00026)	(0.00130)	(0.00156)	(0.00032)	(0.00134)	(0.00166)	23.1%	3.1%	6.4%
Above 50 kV but below 220 kV	(0.00482)	(0.00286)	(0.00768)	(0.00450)	(0.00290)	(0.00740)	-6.6%	1.4%	-3.6%
At 220 kV	(0.01508)	(0.00288)	(0.01796)	(0.01339)	(0.00293)	(0.01632)	-11.2%	1.7%	-9.1%
CPP Event Energy Charge - \$/kWh	0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
Summer CPP Non-Event Credit									
On-Peak Demand Credit - \$/kW	0.00	(5.68)	(5.68)	0.00	(5.68)	(5.68)		0.0%	0.0%
California Climate Credit - \$/kWh/Meter/Month	(71.00)	-	(71.00)	(71.00)	-	(71.00)	0.0%		0.0%

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October 2023 Rates		
Delivery	Generation	Total Rate

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

Delivery Change	Generation Change	Total Rate Change
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TOU-PA-2 (Rate A) - GF

Energy Charge - \$/kWh

Summer Season

On-Peak

0.18026

0.32915

0.50941

0.15909

0.23999

0.39908

-11.7%

-27.1%

-21.7%

Mid-peak

0.09255

0.15040

0.24295

0.08597

0.13515

0.22112

-7.1%

-10.1%

-9.0%

Off-Peak

0.04960

0.10192

0.15152

0.04908

0.10551

0.15459

-1.0%

3.5%

2.0%

Winter Season

Mid-peak

0.04904

0.13937

0.18841

0.04867

0.14686

0.19553

-0.8%

5.4%

3.8%

Off-Peak

0.03575

0.09212

0.12787

0.03649

0.09541

0.13190

2.1%

3.6%

3.2%

Customer Charge - \$/month

72.69

0.00

72.69

32.75

0.00

32.75

-54.9%

-54.9%

Facilities Related

Demand Charge - \$/kW

11.72

0.00

11.72

9.95

0.00

9.95

-15.1%

-15.1%

Wind Machine Credit- \$/kW

0.00

(10.16)

(10.16)

0.00

(8.84)

(8.84)

-13.0%

-13.0%

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV

(0.00040)

(0.00209)

(0.00249)

(0.00059)

(0.00213)

(0.00272)

47.5%

1.9%

9.2%

From 51 kV to 219 kV

(0.00810)

(0.00467)

(0.01277)

(0.01020)

(0.00475)

(0.01495)

25.9%

1.7%

17.1%

220 kV and above

(0.02830)

(0.00469)

(0.03299)

(0.02561)

(0.00482)

(0.03043)

-9.5%

2.8%

-7.8%

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV

-0.13

0.00

(0.13)

-0.17

0.00

(0.17)

30.8%

30.8%

From 51 kV to 219 kV

-2.65

0.00

(2.65)

-2.98

0.00

(2.98)

12.5%

12.5%

220 kV and above

-9.26

0.00

(9.26)

-7.49

0.00

(7.49)

-19.1%

-19.1%

California Climate Credit - \$/kWh/Meter/Month

(71.00)

-

(71.00)

(71.00)

-

(71.00)

0.0%

0.0%

TOU-PA-2 (Rate B) - GF

Energy Charge - \$/kWh

Summer Season

On-Peak

0.03269

0.11325

0.14594

0.03365

0.11724

0.15089

2.9%

3.5%

3.4%

Mid-peak

0.03269

0.10466

0.13735

0.03365

0.10850

0.14215

2.9%

3.7%

3.5%

Off-Peak

0.03269

0.10192

0.13461

0.03365

0.10551

0.13916

2.9%

3.5%

3.4%

Winter Season

Mid-peak

0.03269

0.13937

0.17206

0.03365

0.14686

0.18051

2.9%

5.4%

4.9%

Off-Peak

0.03269

0.09212

0.12481

0.03365

0.09541

0.12906

2.9%

3.6%

3.4%

Customer Charge - \$/month

72.69

0.00

72.69

32.75

0.00

32.75

-54.9%

-54.9%

Facilities Related

Demand Charge - \$/kW

17.53

0.00

17.53

15.84

0.00

15.84

-9.6%

-9.6%

Time Related Demand Charge - \$/kW

Summer Season

On-Peak

0.00

11.14

11.14

0.00

7.44

7.44

-33.2%

-33.2%

Mid-Peak

0.00

3.41

3.41

0.00

2.33

2.33

-31.7%

-31.7%

Wind Machine Credit- \$/kW

0.00

(10.16)

(10.16)

0.00

(8.84)

(8.84)

-13.0%

-13.0%

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV

-0.21

0.00

(0.21)

-0.31

0.00

(0.31)

47.6%

47.6%

From 51 kV to 219 kV

-4.31

0.00

(4.31)

-5.33

0.00

(5.33)

23.7%

23.7%

220 kV and above

-15.07

0.00

(15.07)

-13.38

0.00

(13.38)

-11.2%

-11.2%

Voltage Discount, Time-Related Demand - \$/kW

From 2 kV to 50 kV

0.00

(0.24)

(0.24)

--

TOU-PA-3-D-RTP

Energy Charge - \$/kWh

Summer Season

On-Peak

0.06217 Variable* Variable*

0.09935 Variable* Variable*

59.8%

Mid-Peak

0.06217 Variable* Variable*

0.06633 Variable* Variable*

6.7%

Off-Peak

0.04103 Variable* Variable*

0.04758 Variable* Variable*

16.0%

Winter Season

Mid-peak

0.06217 Variable* Variable*

0.03741 Variable* Variable*

-39.8%

Off-Peak

0.04103 Variable* Variable*

0.03357 Variable* Variable*

-18.2%

Super-Off-Peak

0.03578 Variable* Variable*

0.03786 Variable* Variable*

5.8%

Customer Charge - \$/month

427.99 0.00 427.99

572.75 0.00 572.75

33.8%

33.8%

Facilities Related

Demand Charge - \$/kW

14.47 0.00 14.47

16.03 0.00 16.03

10.8%

10.8%

Time Related Demand Charge - \$/kW

Summer Season

On-Peak

4.00 0.00 4.00

3.83 0.00 3.83

-4.3%

-4.3%

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV

(0.21) 0.00 (0.21)

(0.31) 0.00 (0.31)

47.6%

47.6%

Above 50 kV but below 220 kV

(4.24) 0.00 (4.24)

(6.01) 0.00 (6.01)

41.7%

41.7%

At 220 kV

(11.11) 0.00 (11.11)

(12.67) 0.00 (12.67)

14.0%

14.0%

Voltage Discount, Time-Related Demand - \$/kW

From 2 kV to 50 kV

(0.07) 0.00 (0.07)

(0.09) 0.00 (0.09)

28.6%

28.6%

From 51 kV to 219 kV

(1.34) 0.00 (1.34)

(1.30) 0.00 (1.30)

-3.0%

-3.0%

220 kV and above

(4.00) 0.00 (4.00)

(3.83) 0.00 (3.83)

-4.3%

-4.3%

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV

(0.00023) (0.00201) (0.00224)

(0.00028) (0.00190) (0.00218)

21.7%

-2.7%

Above 50 kV but below 220 kV

(0.00419) (0.00449) (0.00868)

(0.00392) (0.00417) (0.00809)

-6.4%

-7.1%

At 220 kV

(0.01279) (0.00453) (0.01732)

(0.01180) (0.00421) (0.01601)

-7.7%

-7.6%

Power Factor Adjustment - \$/kVA

Greater than 50 kV

0.66 0.00 0.66

0.76 0.00 0.76

15.2%

15.2%

50 kV or less

0.52 0.00 0.52

0.60 0.00 0.60

15.4%

15.4%

TOU-PA-3-E4

Energy Charge - \$/kWh

Summer Season

On-Peak

0.09038 0.44668 0.53706

0.12416 0.39559 0.51975

37.4%

-11.4%

-3.2%

Mid-peak

0.09038 0.12294 0.21332

0.09114 0.12491 0.21605

0.8%

1.6%

1.3%

Off-Peak

0.04988 0.08145 0.13133

0.05627 0.10005 0.15632

12.8%

22.8%

19.0%

Winter Season

Mid-peak

0.06625 0.14889 0.21514

0.05421 0.17655 0.23076

-18.2%

18.6%

7.3%

Off-Peak

0.05915 0.11861 0.17776

0.04970 0.14064 0.19034

-16.0%

18.6%

7.1%

Super-Off-Peak

0.04148 0.04317 0.08465

0.03846 0.05119 0.08965

-7.3%

18.6%

5.9%

Customer Charge - \$/month

427.99 0.00 427.99

572.75 0.00 572.75

33.8%

33.8%

Facilities Related

Demand Charge - \$/kW

12.31 0.00 12.31

13.71 0.00 13.71

11.4%

11.4%

Power Factor Adjustment - \$/kVA

Greater than 50 kV

0.66 0.00 0.66

0.76 0.00 0.76

15.2%

15.2%

50 kV or less

0.52 0.00 0.52

0.60 0.00 0.60

15.4%

15.4%

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV

(0.17) 0.00 (0.17)

(0.25) 0.00 (0.25)

47.1%

47.1%

Above 50 kV but below 220 kV

(3.42) 0.00 (3.42)

(4.91) 0.00 (4.91)

43.6%

43.6%

At 220 kV

(8.95) 0.00 (8.95)

(10.35) 0.00 (10.35)

15.6%

15.6%

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV

(0.00044) (0.00201) (0.00245)

(0.00055) (0.00190) (0.00245)

25.0%

-5.5%

0.0%

Above 50 kV but below 220 kV

(0.00843) (0.00449) (0.01292)

(0.00869) (0.00417) (0.01286)

3.1%

-7.1%

-0.5%

At 220 kV

(0.02438) (0.00453) (0.02891)

(0.02293) (0.00421) (0.02714)

-5.9%

-7.1%

-6.1%

TOU-PA-3-E5

Energy Charge - \$/kWh

Summer Season

On-Peak

0.10068 0.65414 0.75482

0.09395 0.51429 0.60824

-6.7%

-21.4%

-19.4%

Mid-peak

0.10068 0.23282 0.33350

0.09395 0.28268 0.37663

-6.7%

21.4%

12.9%

Off-Peak

0.05310 0.08128 0.13438

0.05340 0.10149 0.15489

0.6%

24.9%

15.3%

Winter Season

Mid-peak

0.06723 0.15572 0.22295

0.06643 0.18861 0.25504

-1.2%

21.1%

14.4%

Off-Peak

0.05993 0.12405 0.18398

0.05943 0.15025 0.20968

-0.8%

21.1%

14.0%

Super-Off-Peak

0.04176 0.04515 0.08691

0.04200 0.05469 0.09669

0.6%

21.1%

11.3%

Customer Charge - \$/month

427.99 0.00 427.99

572.75 0.00 572.75

33.8%

33.8%

Facilities Related

Demand Charge - \$/kW

12.31 0.00 12.31

13.71 0.00 13.71

11.4%

11.4%

Power Factor Adjustment - \$/kVA

Greater than 50 kV

0.66 0.00 0.66

0.76 0.00 0.76

15.2%

15.2%

50 kV or less

0.52 0.00 0.52

0.60 0.00 0.60

--

October 2023 Rates		
Delivery	Generation	Total Rate

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

Delivery Change	Generation Change	Total Rate Change

TOU-PA-3-D4

Energy Charge - \$/kWh

Summer Season

On-Peak
Mid-peak
Off-Peak

Winter Season

Mid-peak
Off-Peak
Super-Off-Peak

Customer Charge - \$/month

Minimum Charge - \$/kW

Summer Season
Winter Season

Facilities Related

Demand Charge - \$/kW

Time Related Demand Charge - \$/kW

Summer Season

On-Peak
Mid-Peak

Winter Season

Mid-Peak
Off-Peak

Power Factor Adjustment - \$/kVA

Greater than 50 kV
50 kV or less

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV
From 51 kV to 219 kV
220 kV and above

Voltage Discount, Time-Related Demand - \$/kW

Summer

From 2 kV to 50 kV
From 51 kV to 219 kV
220 kV and above

Winter

From 2 kV to 50 kV
From 51 kV to 219 kV
220 kV and above

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV
From 51 kV to 219 kV
220 kV and above

0.06217 0.13478 0.19695
0.06217 0.12294 0.18511
0.04103 0.08145 0.12248

0.06217 0.10425 0.16642
0.04103 0.10491 0.14594
0.03578 0.05517 0.09095

427.99 0.00 427.99

0.00 0.00 0.00
0.00 0.00 0.00

14.47 0.00 14.47

4.00 16.76 20.76
0.00 0.00 0.00

0.00 3.62 3.62
0.00 0.00 0.00

0.66 0.00 0.66
0.52 0.00 0.52

(0.21) 0.00 (0.21)
(4.24) 0.00 (4.24)
(11.11) 0.00 (11.11)

(0.07) (0.26) (0.33)
(1.34) (0.60) (1.94)
(4.00) (0.60) (4.60)

(0.07) (0.26) (0.33)
(1.34) (0.60) (1.94)
(4.00) (0.60) (4.60)

(0.00023) (0.00129) (0.00152)
(0.00419) (0.00282) (0.00701)
(0.01279) (0.00286) (0.01565)

0.09935 0.14883 0.24818
0.06633 0.12491 0.19124
0.04758 0.10005 0.14763

0.03741 0.12330 0.16071
0.03357 0.11883 0.15240
0.03786 0.07344 0.11130

572.75 0.00 572.75

0.00 0.00 0.00
0.00 0.00 0.00

16.03 0.00 16.03

3.83 14.45 18.28
0.00 0.00 0.00

0.00 4.34 4.34
0.00 0.00 0.00

0.76 0.00 0.76
0.60 0.00 0.60

(0.31) 0.00 (0.31)
(6.01) 0.00 (6.01)
(12.67) 0.00 (12.67)

(0.09) (0.32) (0.41)
(1.30) (0.74) (2.04)
(3.83) (0.75) (4.58)

0.00 (0.15) (0.15)
0.00 (0.34) (0.34)
0.00 (0.34) (0.34)

(0.00028) (0.00134) (0.00162)
(0.00392) (0.00289) (0.00681)
(0.01180) (0.00292) (0.01472)

59.8% 10.4% 26.0%
6.7% 1.6% 3.3%
16.0% 22.8% 20.5%

-39.8% 18.3% -3.4%
-18.2% 13.3% 4.4%
5.8% 33.1% 22.4%

33.8% 33.8%

10.8% 10.8%

-4.3% -13.8% -11.9%

19.9% 19.9%

15.2% 15.2%
15.4% 15.4%

47.6% 47.6%
41.7% 41.7%
14.0% 14.0%

28.6% 23.1% 24.2%
-3.0% 23.3% 5.2%
-4.3% 25.0% -0.4%

-100.0% -42.3% -54.5%
-100.0% -43.3% -82.5%
-100.0% -43.3% -92.6%

21.7% 3.9% 6.6%
-6.4% 2.5% -2.9%
-7.7% 2.1% -5.9%

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TOU-PA-3-D5

Energy Charge - \$/kWh

Summer Season

On-Peak

0.06602 0.24682 0.31284

0.06454 0.33069 0.39523

-2.2% 34.0% 26.3%

Mid-peak

0.06602 0.23282 0.29884

0.06454 0.28268 0.34722

-2.2% 21.4% 16.2%

Off-Peak

0.04223 0.08128 0.12351

0.04427 0.10149 0.14576

4.8% 24.9% 18.0%

Winter Season

Mid-peak

0.06602 0.10825 0.17427

0.06454 0.13234 0.19688

-2.2% 22.3% 13.0%

Off-Peak

0.04223 0.10894 0.15117

0.04427 0.12754 0.17181

4.8% 17.1% 13.7%

Super-Off-Peak

0.03583 0.05718 0.09301

0.03817 0.07875 0.11692

6.5% 37.7% 25.7%

Customer Charge - \$/month

427.99 0.00 427.99

572.75 0.00 572.75

33.8% 33.8%

Minimum Charge - \$/kW

Summer Season

0.00 0.00

0.00 0.00 0.00

Winter Season

0.00 0.00

0.00 0.00 0.00

Facilities Related

Demand Charge - \$/kW

14.98 0.00 14.98

16.03 0.00 16.03

7.0% 7.0%

Time Related Demand Charge - \$/kW

Summer Season

On-Peak

2.97 13.92 16.89

2.88 6.77 9.65

-3.0% -51.4% -42.9%

Mid-Peak

0.00 0.00

0.00 0.00 0.00

Winter Season

Mid-Peak

0.00 2.98 2.98

0.00 2.98 2.98

0.0% 0.0%

Off-Peak

0.00 0.00

0.00 0.00 0.00

Power Factor Adjustment - \$/kVA

Greater than 50 kV

0.66 0.00 0.66

0.76 0.00 0.76

15.2% 15.2%

50 kV or less

0.52 0.00 0.52

0.60 0.00 0.60

15.4% 15.4%

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV

(0.22) 0.00 (0.22)

(0.31) 0.00 (0.31)

40.9% 40.9%

From 51 kV to 219 kV

(4.43) 0.00 (4.43)

(6.01) 0.00 (6.01)

35.7% 35.7%

220 kV and above

(11.62) 0.00 (11.62)

(12.67) 0.00 (12.67)

9.0% 9.0%

Voltage Discount, Time-Related Demand - \$/kW

Summer

From 2 kV to 50 kV

(0.05) (0.22) (0.27)

(0.07) (0.15) (0.22)

40.0% -31.8% -18.5%

From 51 kV to 219 kV

(0.99) (0.50) (1.49)

(0.98) (0.35) (1.33)

-1.0% -30.0% -10.7%

220 kV and above

(2.97) (0.50) (3.47)

(2.88) (0.35) (3.23)

-3.0% -30.0% -6.9%

Winter

From 2 kV to 50 kV

(0.05) (0.22) (0.27)

0.00 (0.10) (0.10)

-100.0% -54.5% -63.0%

From 51 kV to 219 kV

(0.99) (0.50) (1.49)

0.00 (0.23) (0.23)

-100.0% -54.0% -84.6%

220 kV and above

(2.97) (0.50) (3.47)

0.00 (0.23) (0.23)

-100.0% -54.0% -93.4%

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV

(0.00021) (0.00141) (0.00162)

(0.00030) (0.00157) (0.00187)

42.9% 11.3% 15.4%

From 51 kV to 219 kV

(0.00386) (0.00311) (0.00697)

(0.00422) (0.00342) (0.00764)

9.3% 10.0% 9.6%

220 kV and above

(0.01205) (0.00315) (0.01520)

(0.01267) (0.00345) (0.01612)

5.1% 9.5% 6.1%

TOU-PA-3-CPP

Energy Charge - \$/kWh

Summer Season

On-Peak

0.06217 0.13478 0.19695

0.09935 0.14883 0.24818

59.8% 10.4% 26.0%

Mid-peak

0.06217 0.12294 0.18511

0.06633 0.12491 0.19124

6.7% 1.6% 3.3%

Off-Peak

0.04103 0.08145 0.12248

0.04758 0.10005 0.14763

16.0% 22.8% 20.5%

Winter Season

Mid-peak

0.06217 0.10425 0.16642

0.03741 0.12330 0.16071

-39.8% 18.3% -3.4%

Off-Peak

0.04103 0.10491 0.14594

0.03357 0.11883 0.15240

-18.2% 13.3% 4.4%

Super-Off-Peak

0.03578 0.05517 0.09095

0.03786 0.07344 0.11130

5.8% 33.1% 22.4%

Customer Charge - \$/month

427.99 0.00 427.99

572.75 0.00 572.75

33.8% 33.8%

Facilities Related

Demand Charge - \$/kW

14.47 0.00 14.47

16.03 0.00 16.03

10.8% 10.8%

Time Related Demand Charge - \$/kW

Summer Season

On-Peak

4.00 16.76 20.76

3.83 14.45 18.28

-4.3% -13.8% -11.9%

Mid-Peak

0.00 0.00 0.00

0.00 0.00 0.00

Winter Season

Mid-Peak

0.00 3.62 3.62

0.00 4.34 4.34

19.9% 19.9%

Off-Peak

0.00 0.00

0.00 0.00 0.00

Power Factor Adjustment - \$/kVA

Greater than 50 kV

0.66 0.00 0.66

0.76 0.00 0.76

15.2% 15.2%

50 kV or less

0.52 0.00 0.52

0.60 0.00 0.60

15.4% 15.4%

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV

(0.21) 0.00 (0.21)

(0.31) 0.00 (0.31)

47.6% 47.6%

Above 50 kV but below 220 kV

(4.24) 0.00 (4.24)

(6.01) 0.00 (6.01)

41.7% 41.7%

At 220 kV

(11.11) 0.00 (11.11)

(12.67) 0.00 (12.67)

14.0% 14.0%

Voltage Discount, Time-Related Demand - \$/kW

Summer

From 2 kV to 50 kV

(0.07) (0.26) (0.33)

(0.09) (0.32) (0.41)

28.6% 23.1% 24.2%

Above 50 kV but below 220 kV

(1.34) (0.60) (1.94)

(1.30) (0.74) (2.04)

-3.0% 23.3% 5.2%

At 220 kV

(4.00) (0.60) (4.60)

(3.83) (0.75) (4.58)

-4.3% 25.0% -0.4%

Winter

From 2 kV to 50 kV

0.00

0.00 (0.15) (0.15)

(0.34) (0.34)

Above 50 kV but below 220 kV

0.00

0.00 (0.34) (0.34)

			October 2023 Rates			Proposed 2025 GRC Rates					
			Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
						0.00	(0.34)	(0.34)			
At 220 kV											
Voltage Discount, Energy - \$/kWh											
From 2 kV to 50 kV			(0.00023)	(0.00129)	(0.00152)	(0.00028)	(0.00134)	(0.00162)	21.7%	3.9%	6.6%
Above 50 kV but below 220 kV			(0.00419)	(0.00282)	(0.00701)	(0.00392)	(0.00289)	(0.00681)	-6.4%	2.5%	-2.9%
At 220 kV			(0.01279)	(0.00286)	(0.01565)	(0.01180)	(0.00292)	(0.01472)	-7.7%	2.1%	-5.9%
CPP Event Energy Charge - \$/kWh			0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
Summer CPP Non-Event Credit											
On-Peak Demand Credit - \$/kW			0.00	(6.18)	(6.18)	0.00	(6.18)	(6.18)		0.0%	0.0%

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October 2023 Rates		
Delivery	Generation	Total Rate

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

Delivery Change	Generation Change	Total Rate Change

TOU-PA-3 (Rate A) - GF

Energy Charge - \$/kWh

Summer Season

On-Peak

Mid-peak

Off-Peak

Winter Season

Mid-peak

Off-Peak

Customer Charge - \$/month

Facilities Related

Demand Charge - \$/kW

Power Factor Adjustment - \$/kVA

Greater than 50 kV

50 kV or less

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV

Above 50 kV but below 220 kV

At 220 kV

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV

Above 50 kV but below 220 kV

At 220 kV

TOU-PA-3 (Rate B) - GF

Energy Charge - \$/kWh

Summer Season

On-Peak

Mid-peak

Off-Peak

Winter Season

Mid-peak

Off-Peak

Customer Charge - \$/month

Minimum Charge - \$/kW

Summer Season

Winter Season

Facilities Related

Demand Charge - \$/kW

Time Related Demand Charge - \$/kW

Summer Season

On-Peak

Mid-Peak

Winter Season

Mid-Peak

Off-Peak

Power Factor Adjustment - \$/kVA

Greater than 50 kV

50 kV or less

Voltage Discount, Facilities Related Demand - \$/kW

From 2 kV to 50 kV

From 51 kV to 219 kV

220 kV and above

Voltage Discount, Time-Related Demand - \$/kW

From 2 kV to 50 kV

From 51 kV to 219 kV

220 kV and above

Voltage Discount, Energy - \$/kWh

From 2 kV to 50 kV

From 51 kV to 219 kV

220 kV and above

API

<=200kW

Summer Average On Peak - \$/kW

Summer Average Mid - Peak - \$/kW

Summer Average Off - Peak - \$/kW

Winter Average Mid - Peak - \$/kW

>=200kW

Summer Average On Peak - \$/kW

Summer Average Mid - Peak - \$/kW

Summer Average Off - Peak - \$/kW

Winter Average Mid - Peak - \$/kW

			October 2023 Rates			Proposed 2025 GRC Rates					
			Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
AL-2-F											
Energy Charge - \$/kWh			0.06311	0.08775	0.15086	0.06616	0.15198	0.21814	4.8%	73.2%	44.6%
Customer Charge - \$/month			11.46	0.00	11.46	8.25	0.00	8.25	-28.0%		-28.0%
AL-2											
Energy Charge - \$/kWh											
Summer Season											
On-Peak			0.31808	0.21412	0.53220	0.25901	0.15556	0.41457	-18.6%	-27.3%	-22.1%
Off-Peak			0.06311	0.08775	0.15086	0.06616	0.15198	0.21814	4.8%	73.2%	44.6%
Winter Season											
On-Peak			0.10094	0.14212	0.24306	0.09478	0.11733	0.21211	-6.1%	-17.4%	-12.7%
Off-Peak			0.06311	0.08775	0.15086	0.06616	0.15198	0.21814	4.8%	73.2%	44.6%
Customer Charge - \$/month			11.46	0.00	11.46	8.25	0.00	8.25	-28.0%		-28.0%
DWL											
Energy Charge - \$/kWh			0.12240	0.08760	0.21000	0.15310	0.15479	0.30789	25.1%	76.7%	46.6%
Rate A - Other Charges											
High Pressure Sodium Vapor Lamp - \$/lamp/month											
50 Watt			8.64	0.00	8.64	11.83	0.00	11.83	36.9%		36.9%
70 Watt			8.66	0.00	8.66	11.86	0.00	11.86	37.0%		37.0%
100 Watt			8.66	0.00	8.66	11.86	0.00	11.86	37.0%		37.0%
150 Watt			8.95	0.00	8.95	12.38	0.00	12.38	38.3%		38.3%
Metal Halide Lamp - \$/lamp/month											
100 Watt					0.00						
175 Watt					0.00						
Mercury Vapor Lamp - \$/lamp/month											
75 Watt			8.67	0.00	8.67	11.86	0.00	11.86	36.8%		36.8%
HPSV Recommended (LED) - \$/lamp/month											
50 Watt			8.58	0.00	8.58	11.74	0.00	11.74	36.8%		36.8%
70 Watt			8.58	0.00	8.58	11.74	0.00	11.74	36.8%		36.8%
100 Watt			8.62	0.00	8.62	11.83	0.00	11.83	37.2%		37.2%
150 Watt			8.90	0.00	8.90	12.50	0.00	12.50	40.4%		40.4%
Rate B - Other Charges											
High Pressure Sodium Vapor Lamp - \$/lamp/month											
50 Watt			2.70	0.00	2.70	0.00	0.00	0.00	-100.0%		-100.0%
70 Watt			2.70	0.00	2.70	0.00	0.00	0.00	-100.0%		-100.0%
100 Watt			2.70	0.00	2.70	0.00	0.00	0.00	-100.0%		-100.0%
150 Watt			2.70	0.00	2.70	0.00	0.00	0.00	-100.0%		-100.0%
Metal Halide Lamp - \$/lamp/month											
100 Watt					0.00						
175 Watt					0.00						
Mercury Vapor Lamp - \$/lamp/month											
75 Watt			2.70	0.00	2.70	0.00	0.00	0.00	-100.0%		-100.0%
HPSV Recommended (LED) - \$/lamp/month											
50 Watt			2.70	0.00	2.70	0.00	0.00	0.00	-100.0%		-100.0%
70 Watt			2.70	0.00	2.70	0.00	0.00	0.00	-100.0%		-100.0%
100 Watt			2.70	0.00	2.70	0.00	0.00	0.00	-100.0%		-100.0%
150 Watt			2.70	0.00	2.70	0.00	0.00	0.00	-100.0%		-100.0%
DWL (Continued)											
Rate C - Other Charges											
High Pressure Sodium Vapor Lamp - \$/lamp/month											
50 Watt			0.31	0.00	0.31	0.00	0.00	0.00	-100.0%		-100.0%
70 Watt			0.31	0.00	0.31	0.00	0.00	0.00	-100.0%		-100.0%
100 Watt			0.31	0.00	0.31	0.00	0.00	0.00	-100.0%		-100.0%
150 Watt			0.31	0.00	0.31	0.00	0.00	0.00	-100.0%		-100.0%
Metal Halide Lamp - \$/lamp/month											
100 Watt					0.00						
175 Watt					0.00						
Mercury Vapor Lamp - \$/lamp/month											
75 Watt			0.35	0.00	0.35	0.00	0.00	0.00	-100.0%		-100.0%
<u>Minimum Charge - \$/month</u>											
Rate A			100.00	0.00	100.00	100.00	0.00	100.00	0.0%		0.0%
Rate B			50.00	0.00	50.00	50.00	0.00	50.00	0.0%		0.0%

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October 2023 Rates		
Delivery	Generation	Total Rate

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

Delivery Change	Generation Change	Total Rate Change

LS-1

Energy Charge - \$/kWh

All Night Service	0.12240	0.08760	0.21000	0.15310	0.15479	0.30789	25.1%	76.7%	46.6%
Midnight Service	0.12240	0.08760	0.21000	0.15310	0.15479	0.30789	25.1%	76.7%	46.6%

Other Charges - All Night/Midnight Service

Incandescent Lamps - \$/lamp/month

103 Watt	10.64	0.00	10.64	12.77	0.00	12.77	20.0%		20.0%
202 Watt	10.60	0.00	10.60	12.72	0.00	12.72	20.0%		20.0%
327 Watt	10.60	0.00	10.60	12.72	0.00	12.72	20.0%		20.0%
448 Watt			0.00						

Mercury Vapor Lamps - \$/lamp/month

100 Watt	10.11	0.00	10.11	12.13	0.00	12.13	20.0%		20.0%
175 Watt	9.88	0.00	9.88	11.86	0.00	11.86	20.0%		20.0%
250 Watt	10.37	0.00	10.37	12.44	0.00	12.44	20.0%		20.0%
400 Watt	10.69	0.00	10.69	12.83	0.00	12.83	20.0%		20.0%
700 Watt	10.64	0.00	10.64	12.77	0.00	12.77	20.0%		20.0%
1,000 Watt			0.00						

High Pressure Sodium Vapor Lamps - \$/lamp/month

50 Watt	9.86	0.00	9.86	11.83	0.00	11.83	20.0%		20.0%
70 Watt	9.88	0.00	9.88	11.86	0.00	11.86	20.0%		20.0%
100 Watt	9.88	0.00	9.88	11.86	0.00	11.86	20.0%		20.0%
150 Watt	10.32	0.00	10.32	12.38	0.00	12.38	20.0%		20.0%
200 Watt	10.68	0.00	10.68	12.82	0.00	12.82	20.0%		20.0%
250 Watt	10.75	0.00	10.75	12.90	0.00	12.90	20.0%		20.0%
310 Watt	10.75	0.00	10.75	12.90	0.00	12.90	20.0%		20.0%
400 Watt	10.68	0.00	10.68	12.82	0.00	12.82	20.0%		20.0%

Low Pressure Sodium Vapor Lamps - \$/lamp/month

35 Watt	12.02	0.00	12.02	14.42	0.00	14.42	20.0%		20.0%
55 Watt	12.02	0.00	12.02	14.42	0.00	14.42	20.0%		20.0%
90 Watt	12.69	0.00	12.69	15.23	0.00	15.23	20.0%		20.0%
135 Watt	12.78	0.00	12.78	15.34	0.00	15.34	20.0%		20.0%
180 Watt	12.80	0.00	12.80	15.36	0.00	15.36	20.0%		20.0%

LS-1 (Continued)

Other Charges - All Night/Midnight Service

Metal Halide Lamps - \$/lamp/month

75 Watt			0.00						
100 Watt	11.14	0.00	11.14	13.37	0.00	13.37	20.0%		20.0%
150 Watt	10.91	0.00	10.91	13.09	0.00	13.09	20.0%		20.0%
175 Watt	11.09	0.00	11.09	13.31	0.00	13.31	20.0%		20.0%
250 Watt	10.88	0.00	10.88	13.06	0.00	13.06	20.0%		20.0%
400 Watt	11.23	0.00	11.23	13.48	0.00	13.48	20.0%		20.0%
1,000 Watt			0.00						
1,500 Watt			0.00						

Light Emitting Diode (LED) Lamps (High Pressure Sodium Vapor Recommended Lamps) - \$/lamp/month

50 Watt	9.78	0.00	9.78	11.74	0.00	11.74	20.0%		20.0%
70 Watt	9.78	0.00	9.78	11.74	0.00	11.74	20.0%		20.0%
100 Watt	9.86	0.00	9.86	11.83	0.00	11.83	20.0%		20.0%
150 Watt	10.42	0.00	10.42	12.50	0.00	12.50	20.0%		20.0%
200 Watt	10.80	0.00	10.80	12.96	0.00	12.96	20.0%		20.0%
250 Watt	11.09	0.00	11.09	13.31	0.00	13.31	20.0%		20.0%
310 Watt	11.97	0.00	11.97	14.36	0.00	14.36	20.0%		20.0%
400 Watt	12.19	0.00	12.19	14.63	0.00	14.63	20.0%		20.0%

LS-1 (Option E)

AB 719 Light Emitting Diode (LED) Lamps - \$/Lamp/Month
(High Pressure Sodium Vapor Recommended Lamps)

50 Watt	11.20	0.00	11.20	13.54	0.00	13.54	20.9%		20.9%
70 Watt	11.26	0.00	11.26	13.58	0.00	13.58	20.6%		20.6%
100 Watt	11.41	0.00	11.41	13.70	0.00	13.70	20.1%		20.1%
150 Watt	12.09	0.00	12.09	14.54	0.00	14.54	20.3%		20.3%
200 Watt	12.73	0.00	12.73	15.39	0.00	15.39	20.9%		20.9%
250 Watt	13.35	0.00	13.35	15.89	0.00	15.89	19.0%		19.0%
310 Watt	14.68	0.00	14.68	17.14	0.00	17.14	16.7%		16.7%
400 Watt	15.07	0.00	15.07	17.60	0.00	17.60	16.8%		16.8%

Distribution Pole Mounted Discount

\$/lamp/month	(4.12)	0.00	(4.12)	(5.41)	0.00	(5.41)	31.3%		31.3%
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Tap Device Annual Charge

\$/device	14.71	0.00	14.71	17.65	0.00	17.65	20.0%		20.0%
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October 2023 Rates		
Delivery	Generation	Total Rate

Proposed 2025 GRC Rates		
Delivery	Generation	Total Rate

Delivery Change	Generation Change	Total Rate Change

LS-2

Energy Charge - \$/kWh

All Night Service	0.12240	0.08760	0.21000	0.15310	0.15479	0.30789	25.1%	76.7%	46.6%
Midnight Service	0.12240	0.08760	0.21000	0.15310	0.15479	0.30789	25.1%	76.7%	46.6%

Multiple Service (Other Charges)

All Night/Midnight Service

Rate A

Incandescent Extended Service Lamps

- \$/lamp/month	0.88	0.00	0.88	1.06	0.00	1.06	20.5%		20.5%
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Mercury Vapor Lamps

- \$/lamp/month	0.88	0.00	0.88	1.06	0.00	1.06	20.5%		20.5%
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Light Emitting Diode (LED) Lamps

- \$/lamp/month	0.88	0.00	0.88	1.06	0.00	1.06	20.5%		20.5%
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High Pressure Sodium Vapor Lamps - \$/lamp/month

50 Watt	0.88	0.00	0.88	1.06	0.00	1.06	20.5%		20.5%
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70 Watt	0.88	0.00	0.88	1.06	0.00	1.06	20.5%		20.5%
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100 Watt	0.88	0.00	0.88	1.06	0.00	1.06	20.5%		20.5%
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150 Watt	0.88	0.00	0.88	1.06	0.00	1.06	20.5%		20.5%
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200 Watt	0.88	0.00	0.88	1.06	0.00	1.06	20.5%		20.5%
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250 Watt	0.88	0.00	0.88	1.06	0.00	1.06	20.5%		20.5%
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310 Watt	0.88	0.00	0.88	1.06	0.00	1.06	20.5%		20.5%
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400 Watt	0.88	0.00	0.88	1.06	0.00	1.06	20.5%		20.5%
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Low Pressure Sodium Vapor Lamps

-\$/lamp/month	0.88	0.00	0.88	1.06	0.00	1.06	20.5%		20.5%
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Metal Halide Lamps

-\$/lamp/month	0.88	0.00	0.88	1.06	0.00	1.06	20.5%		20.5%
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Induction Lamps

-\$/lamp/month	0.88	0.00	0.88	1.06	0.00	1.06	20.5%		20.5%
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All Other Lamps

-\$/lamp/month	0.88	0.00	0.88	1.06	0.00	1.06	20.5%		20.5%
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Rate B

Incandescent Extended Service Lamps

- \$/lamp/month	2.70	0.00	2.70	3.24	0.00	3.24	20.0%		20.0%
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Mercury Vapor Lamps

- \$/lamp/month	2.70	0.00	2.70	3.24	0.00	3.24	20.0%		20.0%
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Light Emitting Diode (LED) Lamps

- \$/lamp/month	2.70	0.00	2.70	3.24	0.00	3.24	20.0%		20.0%
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High Pressure Sodium Vapor Lamps - \$/lamp/month

50 Watt	2.70	0.00	2.70	3.24	0.00	3.24	20.0%		20.0%
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70 Watt	2.70	0.00	2.70	3.24	0.00	3.24	20.0%		20.0%
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100 Watt	2.70	0.00	2.70	3.24	0.00	3.24	20.0%		20.0%
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150 Watt	2.70	0.00	2.70	3.24	0.00	3.24	20.0%		20.0%
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200 Watt	2.70	0.00	2.70	3.24	0.00	3.24	20.0%		20.0%
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250 Watt	2.70	0.00	2.70	3.24	0.00	3.24	20.0%		20.0%
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310 Watt	2.70	0.00	2.70	3.24	0.00	3.24	20.0%		20.0%
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400 Watt	2.70	0.00	2.70	3.24	0.00	3.24	20.0%		20.0%
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Low Pressure Sodium Vapor Lamps

-\$/lamp/month	2.70	0.00	2.70	3.24	0.00	3.24	20.0%		20.0%
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Metal Halide Lamps

-\$/lamp/month	2.70	0.00	2.70	3.24	0.00	3.24	20.0%		20.0%
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Induction Lamps

-\$/lamp/month	2.70	0.00	2.70	3.24	0.00	3.24	20.0%		20.0%
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All Other Lamps

-\$/lamp/month	2.70	0.00	2.70	3.24	0.00	3.24	20.0%		20.0%
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LS-2 (Continued)

Series Service

Series Service Power Factor - \$/kVar	0.52	0.00	0.52	0.60	0.00	0.60	15.4%		15.4%
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All Night/Midnight Service

Incandescent Extended Service Lamps

-\$/lamp/month	13.01	0.00	13.01	15.61	0.00	15.61	20.0%		20.0%
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Mercury Vapor Lamps

-\$/lamp/month	13.01	0.00	13.01	15.61	0.00	15.61	20.0%		20.0%
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High Pressure Sodium Vapor Lamps - \$/lamp/month

50 Watt	13.01	0.00	13.01	15.61	0.00	15.61	20.0%		20.0%
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70 Watt	13.01	0.00	13.01	15.61	0.00	15.61	20.0%		20.0%
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100 Watt	13.01	0.00	13.01	15.61	0.00	15.61	20.0%		20.0%
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150 Watt	13.01	0.00	13.01	15.61	0.00	15.61	20.0%		20.0%
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200 Watt	13.01	0.00	13.01	15.61	0.00	15.61	20.0%		20.0%
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250 Watt	N/A			N/A					
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310 Watt	N/A			N/A					
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400 Watt	N/A			N/A					
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Low Pressure Sodium Vapor Lamps

-\$/lamp/month	13.01	0.00	13.01	15.61	0.00	15.61	20.0%		20.0%
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Metal Halide Lamps

-\$/lamp/month	N/A			N/A					
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All Other Lamps

-\$/lamp/month	13.01	0.00	13.01	15.61	0.00	15.61	20.0%		20.0%
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Series Service Voltage Discount, Energy - \$/kWh	0.00000	(0.00381)	(0.00381)	0.00000	(0.00345)	(0.00345)		-9.4%	-9.4%
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			October 2023 Rates			Proposed 2025 GRC Rates					
			Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
LS-2 Continued - (Optional Service - Relamp)											
Incandescent Extended Service Lamps											
	-\$/lamp/month		N/A			N/A					
Mercury Vapor Lamps											
	-\$/lamp/month		N/A			N/A					
High Pressure Sodium Vapor Lamps - \$/lamp/month											
	50 Watt		0.71	0.00	0.71	0.86	0.00	0.86	21.1%		21.1%
	70 Watt		0.71	0.00	0.71	0.86	0.00	0.86	21.1%		21.1%
	100 Watt		0.71	0.00	0.71	0.86	0.00	0.86	21.1%		21.1%
	150 Watt		0.71	0.00	0.71	0.86	0.00	0.86	21.1%		21.1%
	200 Watt		0.72	0.00	0.72	0.86	0.00	0.86	19.4%		19.4%
	250 Watt		0.71	0.00	0.71	0.86	0.00	0.86	21.1%		21.1%
	310 Watt			0.00							
	400 Watt		0.71	0.00	0.71	0.86	0.00	0.86	21.1%		21.1%
Low Pressure Sodium Vapor Lamps											
	-\$/lamp/month		N/A			N/A					
Metal Halide Lamps											
	-\$/lamp/month		N/A			N/A					
All Other Lamps											
	-\$/lamp/month		N/A			N/A					
LS-3											
Energy Charge - \$/kWh			0.06311	0.08775	0.15086	0.06616	0.15198	0.21814	4.8%	73.2%	44.6%
Customer Charge - \$/month											
	Multiple Service		11.46	0.00	11.46	8.25	0.00	8.25	-28.0%		-28.0%
	Series Service		444.05	0.00	444.05	434.84	0.00	434.84	-2.1%		-2.1%
Optional Relamp Service Charge (\$/lamp/month)											
High Pressure Sodium Vapor Lamps											
	50 Watt		0.71	0.00	0.71	0.86	0.00	0.86	21.1%		21.1%
	70 Watt		0.71	0.00	0.71	0.86	0.00	0.86	21.1%		21.1%
	100 Watt		0.71	0.00	0.71	0.86	0.00	0.86	21.1%		21.1%
	150 Watt		0.71	0.00	0.71	0.86	0.00	0.86	21.1%		21.1%
	200 Watt		0.72	0.00	0.72	0.86	0.00	0.86	19.4%		19.4%
	250 Watt		0.71	0.00	0.71	0.86	0.00	0.86	21.1%		21.1%
	400 Watt		0.71	0.00	0.71	0.86	0.00	0.86	21.1%		21.1%
Series Service											
	Voltage Discount, Energy - \$/kWh		0.00000	(0.00381)	(0.00381)	0.00000	(0.00345)	(0.00345)		-9.4%	-9.4%
OL-1											
Energy Charge - \$/kWh											
	All Night Service		0.12240	0.08760	0.21000	0.15310	0.15479	0.30789	25.1%	76.7%	46.6%
	Midnight Service		0.12240	0.08760	0.21000	0.15310	0.15479	0.30789	25.1%	76.7%	46.6%
Pole Charge - \$/pole/month			2.24	0.00	2.24	2.44	0.00	2.44	8.9%		8.9%
Other Charges - All Night/Midnight Service											
Mercury Vapor Lamps - \$/lamp/month											
	175 Watt		9.88	0.00	9.88	11.86	0.00	11.86	20.0%		20.0%
	400 Watt		10.69	0.00	10.69	12.83	0.00	12.83	20.0%		20.0%
High Pressure Sodium Vapor Lamps - \$/lamp/month											
	50 Watt		9.86	0.00	9.86	11.83	0.00	11.83	20.0%		20.0%
	70 Watt		9.88	0.00	9.88	11.86	0.00	11.86	20.0%		20.0%
	100 Watt		9.88	0.00	9.88	11.86	0.00	11.86	20.0%		20.0%
	150 Watt		10.32	0.00	10.32	12.38	0.00	12.38	20.0%		20.0%
	200 Watt		10.68	0.00	10.68	12.82	0.00	12.82	20.0%		20.0%
	250 Watt		10.75	0.00	10.75	12.90	0.00	12.90	20.0%		20.0%
	400 Watt		10.68	0.00	10.68	12.82	0.00	12.82	20.0%		20.0%
	1000 Watt		13.85	0.00	13.85	16.62	0.00	16.62	20.0%		20.0%
Low Pressure Sodium Vapor Lamps - \$/lamp/month											
	35 Watt				0.00						
	55 Watt		12.02	0.00	12.02	14.42	0.00	14.42	20.0%		20.0%
	90 Watt		12.69	0.00	12.69	15.23	0.00	15.23	20.0%		20.0%
	135 Watt		12.78	0.00	12.78	15.34	0.00	15.34	20.0%		20.0%
	180 Watt		12.80	0.00	12.80	15.36	0.00	15.36	20.0%		20.0%
Metal Halide Lamps - \$/lamp/month											
	70 Watt				0.00						
	100 Watt		11.14	0.00	11.14	13.37	0.00	13.37	20.0%		20.0%
	175 Watt		11.09	0.00	11.09	13.31	0.00	13.31	20.0%		20.0%
	250 Watt		10.88	0.00	10.88	13.06	0.00	13.06	20.0%		20.0%
	400 Watt		11.23	0.00	11.23	13.48	0.00	13.48	20.0%		20.0%
	1,000 Watt		11.23	0.00	11.23	13.48	0.00	13.48	20.0%		20.0%
	1,500 Watt				0.00						
HPSV Recommended (LED) - \$/lamp/month											
	50 Watt		9.78	0.00	9.78	11.74	0.00	11.74	20.0%		20.0%
	70 Watt		9.78	0.00	9.78	11.74	0.00	11.74	20.0%		20.0%
	100 Watt		9.86	0.00	9.86	11.83	0.00	11.83	20.0%		20.0%
	150 Watt		10.42	0.00	10.42	12.50	0.00	12.50	20.0%		20.0%
	200 Watt		10.80	0.00	10.80	12.96	0.00	12.96	20.0%		20.0%
	250 Watt		11.09	0.00	11.09	13.31	0.00	13.31	20.0%		20.0%
	400 Watt		12.19	0.00	12.19	14.63	0.00	14.63	20.0%		20.0%
	1000 Watt		14.71	0.00	14.71	17.65	0.00	17.65	20.0%		20.0%
Distribution Pole Mounted Discount											
	\$/lamp/month		(4.12)	0.00	(4.12)	(5.41)	0.00	(5.41)	31.3%		31.3%

			October 2023 Rates			Proposed 2025 GRC Rates					
			Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TC-1											
Energy Charge - \$/kWh			0.11869	0.12816	0.24685	0.07585	0.13219	0.20804	-36.1%	3.1%	-15.7%
Customer Charge - \$/day			0.788	0.000	0.788	0.745	0.000	0.745	-5.5%		-5.5%
Three-Phase Service - \$/day			0.031	0.000	0.031	0.029	0.000	0.029	-6.5%		-6.5%
WTR											
Energy Charge - \$/Device/Month											
25	0 - 25 kWh/month		2.98	3.20	6.18	1.89	3.30	5.19	-36.6%	3.1%	-16.0%
50	26 - 50 kWh/month		5.93	6.41	12.34	3.79	6.61	10.40	-36.1%	3.1%	-15.7%
100	51 - 100 kWh/month		11.87	12.82	24.69	7.59	13.22	20.81	-36.1%	3.1%	-15.7%
150	101 - 150 kWh/month		17.82	19.22	37.04	11.39	19.83	31.22	-36.1%	3.2%	-15.7%
200	151 - 200 kWh/month		23.74	25.63	49.37	15.18	26.44	41.62	-36.1%	3.2%	-15.7%
250	201 - 250 kWh/month		29.67	32.04	61.71	18.97	33.05	52.02	-36.1%	3.2%	-15.7%
300	251 - 300 kWh/month		35.61	38.45	74.06	22.76	39.66	62.42	-36.1%	3.1%	-15.7%
350	301 - 350 kWh/month		41.54	44.86	86.40	26.56	46.27	72.83	-36.1%	3.1%	-15.7%
400	351 - 400 kWh/month		47.48	51.26	98.74	30.35	52.88	83.23	-36.1%	3.2%	-15.7%
450	401 - 450 kWh/month		53.41	57.67	111.08	34.14	59.49	93.63	-36.1%	3.2%	-15.7%
500	451 - 500 kWh/month		59.38	64.08	123.46	37.94	66.10	104.04	-36.1%	3.2%	-15.7%
900	501 - 900 kWh/month		106.84	115.34	222.18	68.28	118.97	187.25	-36.1%	3.1%	-15.7%
1350	901 - 1350 kWh/month		160.23	173.02	333.25	102.41	178.46	280.87	-36.1%	3.1%	-15.7%
1800	1351 - 1800 kWh/month		213.64	230.69	444.33	136.52	237.94	374.46	-36.1%	3.1%	-15.7%
2250	1801 - 2250 kWh/month		267.05	288.36	555.41	170.67	297.43	468.10	-36.1%	3.1%	-15.7%
2700	2251 - 2700 kWh/month		320.48	346.03	666.51	204.81	356.91	561.72	-36.1%	3.1%	-15.7%
Customer Charge - \$/Month			11.70	0.00	11.70	14.77	0.00	14.77	26.2%		26.2%
Three-Phase Service - \$/day			0.031	0.000	0.031	0.029	0.000	0.029	-6.5%		-6.5%
Inspection Charge - \$/Device/Month			15.23	0.00	15.23	15.23	0.00	15.23	0.0%		0.0%
Initialization of Service Charge - One-time charge			7.31	0.00	7.31	7.31	0.00	7.31	0.0%		0.0%
AMI Devices											
Energy Charge - \$/Device/Month											
29	29 kWh/month		3.44	3.72	7.16	2.20	3.83	6.03	-36.0%	3.0%	-15.8%
Customer Charge - \$/month			3.78	0.00	3.78	3.46	0.00	3.46	-8.5%		-8.5%
Inspection Charge - \$/Device/Month			15.23	0.00	15.23	15.23	0.00	15.23	0.0%		0.0%
Initialization of Service Charge - One-time charge			10.42	0.00	10.42	10.42	0.00	10.42	0.0%		0.0%
Wi-Fi-1											
Energy Charge - \$/Device/Month			3.10	3.28	6.38	2.01	3.38	5.39	-35.2%	3.0%	-15.5%
Customer Charge - \$/Month			3.78	0.00	3.78	3.46	0.00	3.46	-8.5%		-8.5%
Inventory/Maintenance Charge - \$/Devoce/Month			2.88	0.00	2.88	2.88	0.00	2.88	0.0%		0.0%
Initialization of Service Charge - One time charge/service account			10.42	0.00	10.42	10.42	0.00	10.42	0.0%		0.0%

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Optional CPP rider < 200 kW

	October 2023 Rates			Proposed 2025 GRC Rates			Delivery Change	Generation Change	Total Rate Change
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate			
CPP Event Energy Charge - \$/kWh									
DOMESTIC	0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
DOMESTIC CARE	0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
TOU-GS-1	0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
GS-2-TOU	0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
TOU-PA-2	0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
Summer Non-Event Energy Credit - \$/kWh									
DOMESTIC (Summer On-Peak Energy Credit)	0.00000	(0.15170)	(0.15170)	0.00000	(0.15170)	(0.15170)		0.0%	0.0%
DOMESTIC CARE (Summer On-Peak Energy Credit)	0.00000	(0.15170)	(0.15170)	0.00000	(0.15170)	(0.15170)		0.0%	0.0%
TOU-GS-1 (Summer On-Peak Energy Credit)	0.00000	(0.13643)	(0.13643)	0.00000	(0.13643)	(0.13643)		0.0%	0.0%
Summer Non-Event Demand Credit - \$/kW									
GS-2-TOU (On-Peak Dmand)	0.00	(6.85)	(6.85)	0.00	(6.85)	(6.85)		0.0%	0.0%
TOU-PA-2	0.00	(5.68)	(5.68)	0.00	(5.68)	(5.68)		0.0%	0.0%

Default CPP rider > 200 kW

<i>TOU-GS-3</i>									
2 p.m. to 6 p.m CPP Event Energy Charge - \$/kWh	0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
Summer On Peak Demand Credit - \$/kW	0.00000	(7.55)	(7.55)	0.00000	(7.55)	(7.55)		0.0%	0.0%
<i>TOU-8-SEC</i>									
2 p.m. to 6 p.m CPP Event Energy Charge - \$/kWh	0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
Summer On Peak Demand Credit - \$/kW	0.00000	(8.22)	(8.22)	0.00000	(8.22)	(8.22)		0.0%	0.0%
<i>TOU-8-PRI</i>									
2 p.m. to 6 p.m CPP Event Energy Charge - \$/kWh	0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
Summer On Peak Demand Credit - \$/kW	0.00000	(8.52)	(8.52)	0.00000	(8.52)	(8.52)		0.0%	0.0%
<i>TOU-8-SUB</i>									
2 p.m. to 6 p.m CPP Event Energy Charge - \$/kWh	0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
Summer On Peak Demand Credit - \$/kW	0.00000	(8.44)	(8.44)	0.00000	(8.44)	(8.44)		0.0%	0.0%
<i>TOU-PA-3</i>									
2 p.m. to 6 p.m CPP Event Energy Charge - \$/kWh	0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
Summer On Peak Demand Credit - \$/kW	0.00000	(6.18)	(6.18)	0.00000	(6.18)	(6.18)		0.0%	0.0%

Appendix C

Bill Impact Frequency Distribution

The bill impacts presented herein provide a comparison of average monthly bills based on current rates and proposed 2025 GRC Phase 2 rates. The charts compare the current and proposed otherwise applicable rate schedules for each of the major rate classes. Comparisons to optional rate schedules are not included. Because the revenue requirement for each set of rates is the same, the charts illustrate the effect of updated cost studies and revenue allocation.

SCE's bill impact analysis is performed using service account level-billing determinants for the period from January 2022 to December 2022. The analysis compares the average percentage change in customer bills that is anticipated when transitioning customers within each rate group from current OAT rates to proposed OAT rates. Results are presented in both graphical and tabulated formats, except for streetlight customer groups where bill impacts are presented for each streetlight schedule. The graphical format summarizes the proportion of customers and the relative magnitude of the impact those customers are expected to experience as they transition to SCE's proposed rates. The tabulated format provides an additional layer of granularity for each customer group and insight into the factors that drive the estimated result. Categories included in the tabulated format include:

- *Average Rates* (expressed in cents/kWh): calculated as the ratio of the average annual bill divided by average annual kWh. The average rates provide a summarized result of the bill impact analysis that allows for a relatively straightforward comparison of relative impact across the different grouping of customers. These average rates are calculated and summarized for the Current and Proposed rates.
- *Seasonal (Summer/Winter) Load Factor* (expressed in %): calculated as the average customer's *ratio* of average demand in a season divided by their maximum non-coincident seasonal peak demand.
- *Summer On-Peak kWh %* (expressed in %): ratio of summer on-peak usage (kWh) to annual usage (kWh). This information provides some relative comparison of TOU kWh usage across the different grouping of customers.
- *Winter Mid-Peak kWh %* (expressed in %): ratio of winter mid-peak usage (kWh) to annual usage (kWh).

- *Winter Super-Off-Peak %* (expressed in %): ratio of winter super-off-peak usage (kWh) to annual usage (kWh).

Figure C-1
Bill Impact for TOU-GS-1

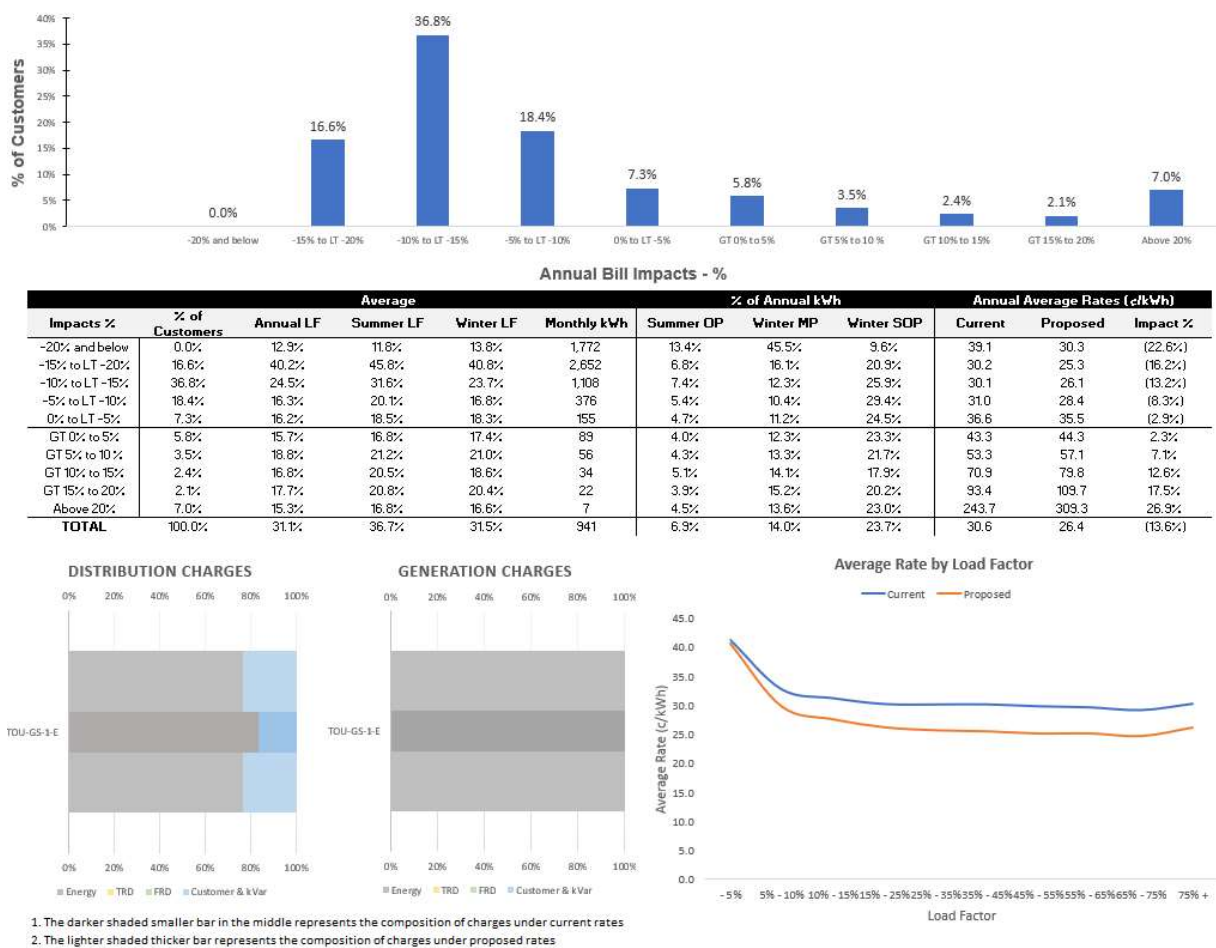
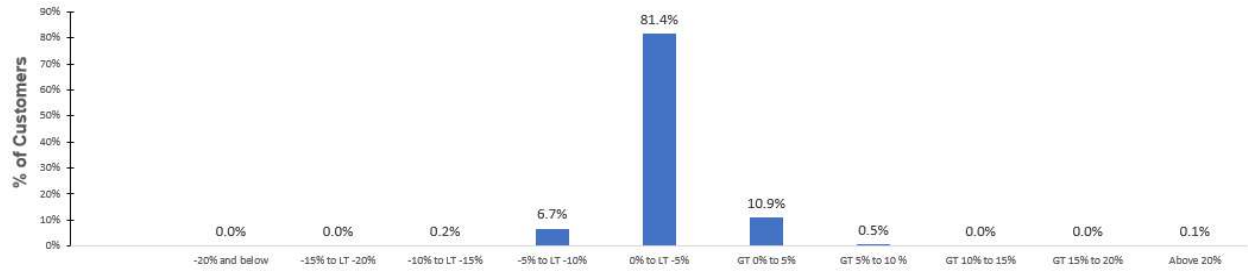


Figure C-2
Bill Impact for TOU-GS-2



Figure C-3
Bill Impact for TOU-GS-3



Annual Bill Impacts - %

Bill Impacts %	% of Customers	Average				% of Annual kWh			* Annual Average Rates (£/kWh)		
		Annual LF	Summer LF	Winter LF	Monthly kWh	Summer OP	Winter MP	Winter SOP	Current	Proposed	Impact %
-20% and below	—	—	—	—	—	—	—	—	—	—	—
-15% to LT -20%	—	—	—	—	—	—	—	—	—	—	—
-10% to LT -15%	0.2%	7.4%	17.3%	5.7%	15,713	12.5%	22.1%	7.3%	78.6	70.3	(10.5%)
-5% to LT -10%	6.7%	17.7%	23.4%	19.2%	42,068	8.5%	16.2%	17.2%	52.2	48.7	(6.8%)
0% to LT -5%	81.4%	41.6%	47.8%	43.2%	85,641	6.4%	13.1%	24.5%	25.5	24.9	(2.0%)
GT 0% to 5%	10.9%	50.8%	56.0%	51.7%	81,424	4.3%	11.2%	27.1%	23.7	24.0	1.0%
GT 5% to 10 %	0.5%	13.8%	16.6%	14.4%	19,822	0.7%	3.8%	45.5%	33.4	35.4	5.9%
GT 10% to 15%	0.0%	9.8%	6.6%	13.7%	4,748	0.7%	19.1%	24.5%	34.2	38.7	13.0%
GT 15% to 20%	0.0%	0.3%	—	0.4%	566	—	18.3%	39.0%	201.6	237.7	17.9%
Above 20%	0.1%	30.2%	35.6%	31.6%	671	4.1%	15.8%	18.2%	108.4	137.9	27.3%
TOTAL	100.0%	41.7%	47.7%	43.3%	81,649	6.2%	13.0%	24.6%	26.2	25.7	(2.0%)

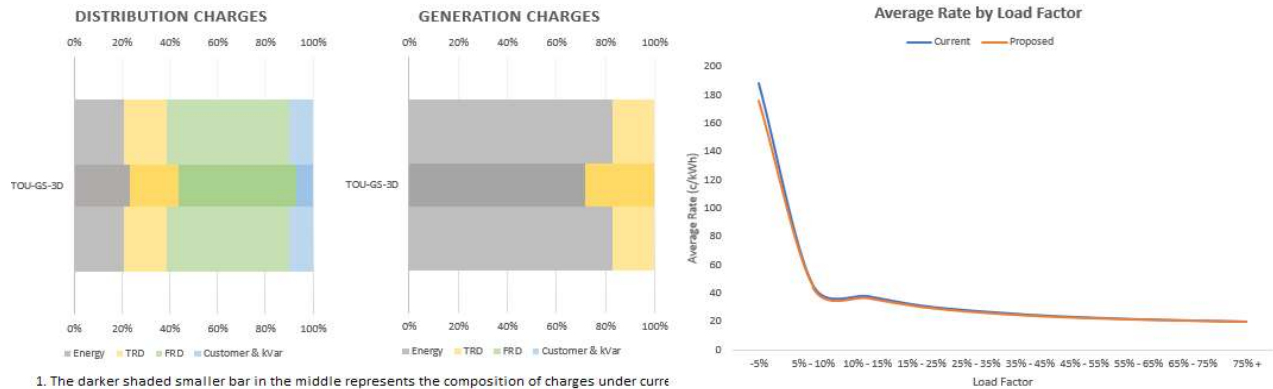
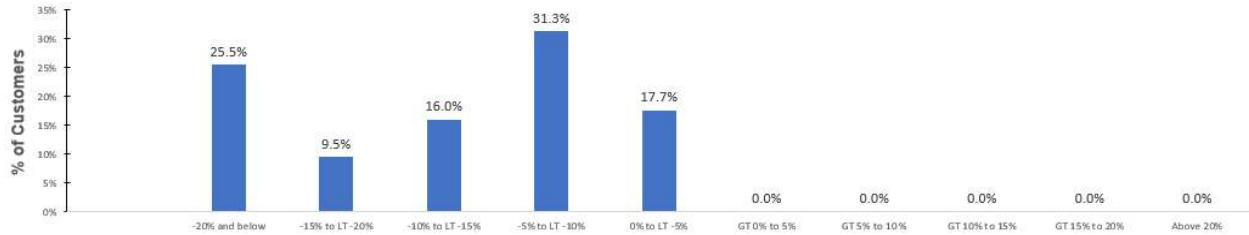


Figure C-4
Bill Impact for TOU-PA-2

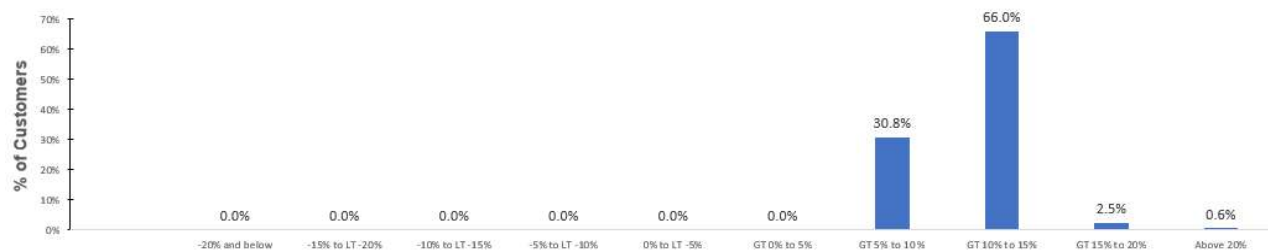


Annual Bill Impacts - %

Bill Impacts %	% of Customers	Average				% of Annual kWh			* Annual Average Rates (¢/kWh)		
		Annual LF	Summer LF	Winter LF	Monthly kWh	Summer OP	Winter MP	Winter SOP	Current	Proposed	Impact %
-20% and below	25.5%	11.4%	17.7%	11.9%	165	5.3%	10.8%	18.8%	98.5	69.1	(29.9%)
-15% to LT -20%	9.5%	12.4%	19.6%	12.1%	714	6.4%	10.8%	19.6%	58.5	48.5	(17.1%)
-10% to LT -15%	16.0%	12.5%	18.9%	12.0%	2,095	7.0%	9.5%	18.8%	41.8	36.8	(12.0%)
-5% to LT -10%	31.3%	22.7%	32.9%	21.9%	8,612	6.6%	10.3%	19.7%	27.5	25.6	(6.8%)
0% to LT -5%	17.7%	45.2%	62.0%	43.3%	27,736	6.8%	9.9%	19.1%	21.3	20.5	(3.5%)
GT 0% to 5%	-	-	-	-	-	-	-	-	-	-	-
GT 5% to 10%	-	-	-	-	-	-	-	-	-	-	-
GT 10% to 15%	-	-	-	-	-	-	-	-	-	-	-
GT 15% to 20%	-	-	-	-	-	-	-	-	-	-	-
Above 20%	-	-	-	-	-	-	-	-	-	-	-
TOTAL	100.0%	35.8%	50.0%	34.3%	8,030	6.7%	10.0%	19.3%	24.9	23.4	(6.1%)



Figure C-5
Bill Impact for TOU-PA-3



Annual Bill Impacts - %

Bill Impacts %	% of Customers	Average				% of Annual kWh			* Annual Average Rates (¢/kWh)		
		Annual LF	Summer LF	Winter LF	Monthly kWh	Summer OP	Winter MP	Winter SOP	Current	Proposed	Impact %
-20% and below	-	-	-	-	-	-	-	-	-	-	-
-15% to LT -20%	-	-	-	-	-	-	-	-	-	-	-
-10% to LT -15%	-	-	-	-	-	-	-	-	-	-	-
-5% to LT -10%	-	-	-	-	-	-	-	-	-	-	-
0% to LT -5%	-	-	-	-	-	-	-	-	-	-	-
GT 0% to 5%	-	-	-	-	-	-	-	-	-	-	-
GT 5% to 10%	30.8%	42.4%	45.7%	44.7%	100,076	5.6%	13.7%	19.8%	21.8	23.9	9.3%
GT 10% to 15%	66.0%	46.9%	59.3%	45.1%	87,550	5.9%	10.3%	22.1%	20.5	22.7	10.9%
GT 15% to 20%	2.5%	23.5%	29.8%	22.9%	15,115	0.3%	1.4%	40.4%	27.5	31.9	15.8%
Above 20%	0.6%	0.6%	32.3%	0.3%	262	6.4%	8.9%	24.3%	347.2	422.5	21.7%
TOTAL	100.0%	45.2%	55.0%	44.3%	89,045	5.8%	11.4%	21.4%	21.0	23.1	10.4%

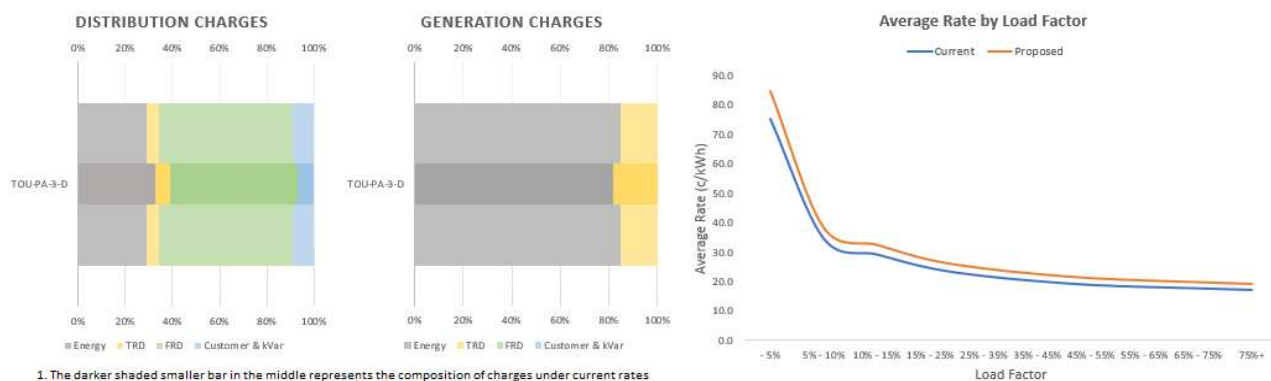


Figure C-6
Bill Impact for TOU-8-SEC (Non-Standby)

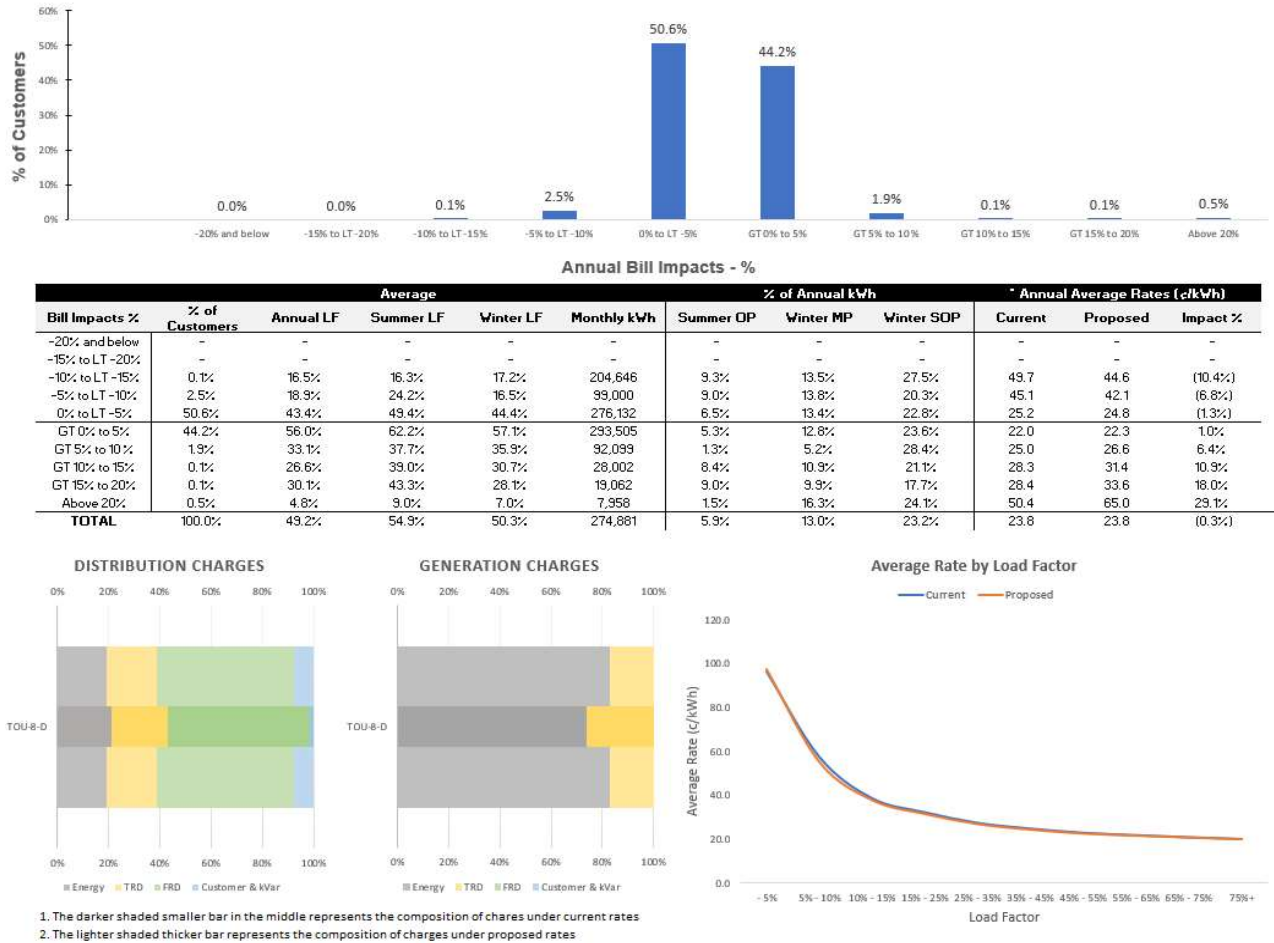
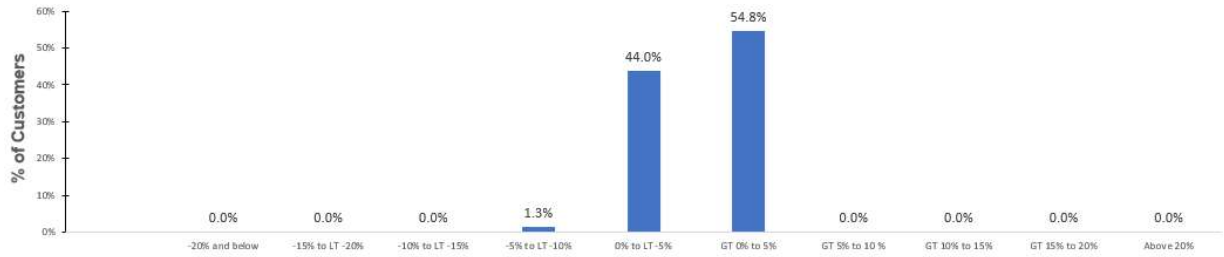


Figure C-7
Bill Impact for TOU-8-PRI (Non-Standby)



Bill Impacts %	Average					% of Annual kWh			Annual Average Rates (¢/kWh)		
	% of Customers	Annual LF	Summer LF	Winter LF	Monthly kWh	Summer OP	Winter MP	Winter SOP	Current	Proposed	Impact %
-20% and below	-	-	-	-	-	-	-	-	-	-	-
-15% to LT -20%	-	-	-	-	-	-	-	-	-	-	-
-10% to LT -15%	-	-	-	-	-	-	-	-	-	-	-
-5% to LT -10%	1.3%	6.4%	8.6%	7.3%	53,834	6.0%	8.3%	10.2%	164.0	153.5	(6.4%)
0% to LT -5%	44.0%	32.0%	38.2%	33.7%	271,951	6.3%	13.9%	19.4%	27.4	27.1	(1.3%)
GT 0% to 5%	54.8%	57.3%	64.3%	59.2%	792,068	5.1%	13.0%	22.5%	20.8	21.0	1.2%
GT 5% to 10%	-	-	-	-	-	-	-	-	-	-	-
GT 10% to 15%	-	-	-	-	-	-	-	-	-	-	-
GT 15% to 20%	-	-	-	-	-	-	-	-	-	-	-
Above 20%	-	-	-	-	-	-	-	-	-	-	-
TOTAL	100.0%	52.3%	58.7%	53.9%	555,194	5.4%	13.2%	21.8%	22.4	22.5	0.5%

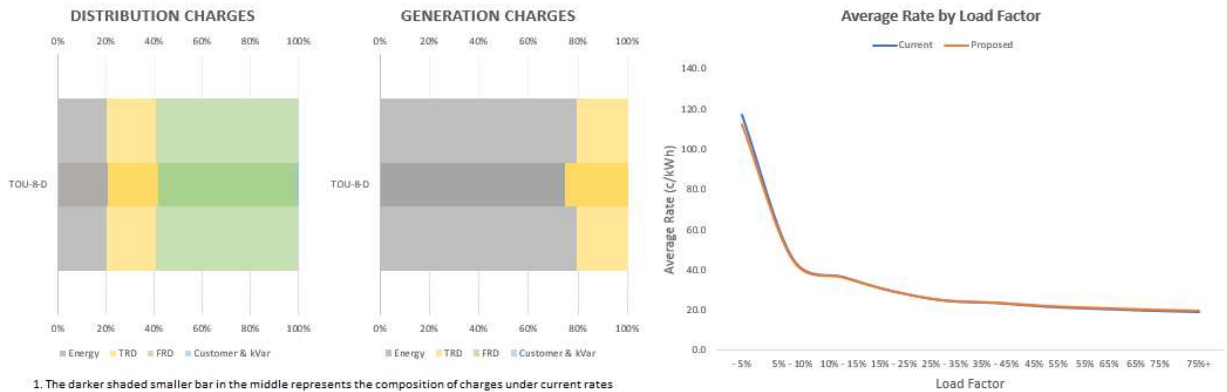


Figure C-8
Bill Impact for Streetlight

[A] Bundled Only Rate Schedules	[B] [\$000] 10/1/2023	[C] [\$000] Proposed	[C] / [B] % Change
AL-2-F	\$13,399	\$18,836	40.6%
AL-2 GF	\$108	\$141	31.1%
LS-3	\$7,894	\$10,619	34.5%
LS-1	\$51,366	\$65,926	28.3%
LS-2	\$36,324	\$51,249	41.1%
OL-1	\$4,251	\$5,709	34.3%
Total Revenues	\$113,343	\$152,481	34.5%

Appendix D

Methodology For Determining Voltage Discounts

Background

Most SCE rate schedules do not differentiate rates by voltage level. Only the large power rates (*i.e.*, TOU-8 and its derivative schedules) are specifically designed to account for varying costs by voltage level. All other rate classes are defined by default at the secondary service level (served at voltages below 2 kV). Nevertheless, a small number of small and medium power customers take service at the primary and subtransmission levels. For these customers, a voltage discount must be developed and applied to the bill.

Analysis

For each applicable rate group, SCE determines dollar discounts for customer distribution costs, generation costs and energy costs, based on service voltage. The discount for distribution-related costs is converted to a peak demand charge discount or distribution energy charge discount, depending on the rate schedule. Generation and distribution cost discounts are applied as a discount to TRD and/or generation energy charges, depending on the rate schedule. The energy cost discount is applied as a discount to distribution and generation energy charges for each rate schedule.

SCE estimates typical customer hook-up costs for different rate groups and for different voltage levels within the group. Although customer costs for primary and subtransmission service would otherwise be lower due to the exclusion of the final line transformer in the cost analysis, certain additional costs associated with high voltage metering tend to offset this savings. Based on SCE's current analysis, no discount, or surcharge, to customer charges is justified for higher voltage service.

The distribution cost components include facilities not used by subtransmission voltage customers, *i.e.*, the distribution substation costs, distribution circuits and distribution land. As such, SCE proposes a discount based upon the differential use of facilities for subtransmission voltage customers not already part of the large power rate class. This marginal cost discount is not adjusted by the EMPC factor. This will provide the correct price signal to customers contemplating switching service voltages. The product of the discount and the peak demands of subtransmission voltage customers in a given group yields a discount revenue that is reflected in peak demand charges. For

non-demand metered customers, the discount is applied to the distribution component of the energy rate.

Peak demand-related rate adjustments are also required due to differential line losses. In revenue allocation, allocators such as design demand and peak demand are converted to generation-level values. For example, serving a secondary voltage TOU-GS-2 customer with 100 kW of demand requires 109 kW to be delivered at the generation level because of line losses. A similarly situated primary voltage customer requires 106 kW to be delivered at the generation level. Likewise, the marginal costs that vary with demand are stated at the generation level. The purpose of doing this is to simplify revenue allocation modeling. The revenue allocation results would be the same if the marginal cost of each component, *e.g.*, distribution circuits, high-voltage substations, etc., were stated as costs at their respective voltage level and if customer demand allocators were adjusted correspondingly. The net effect is that the metered-level demand for a primary voltage customer requires an approximate 2.22 percent discount from the peak-demand rate designed for an average TOU-GS-2 customer, and, similarly, an approximate 1.83 percent discount from an average TOU-GS-3 customer. A subtransmission voltage customer requires an approximate 32.13 percent and an approximate 37.13 percent discount from the peak-demand rate designed for an average TOU-GS-2 and TOU-GS-3 customer, respectively. For non-demand metered rate groups, discounts apply to distribution energy rates.

As with the distribution design demand-related costs, the time-related generation costs require adjustments due to differential demand-related line losses. For non-demand metered customers, the discounts due to differential demand-related line losses are applied as a discount to the generation portion of the energy rate.

Finally, differential energy line losses result in different marginal energy costs for service at different voltages. SCE's proposed discount is, once again, based on marginal energy costs as opposed to the allocated energy costs applicable to each rate group so as to provide the appropriate price signal for customers evaluating the economics of switching to a higher voltage of service. Because line loss differentials across time periods are relatively small, SCE proposes to base the

energy discounts on levelized energy line losses. For subtransmission customers, this results in discounts of 31.01 percent and 30.60 percent for on-peak marginal energy costs for TOU-GS-2 and TOU-GS-3 customers, respectively, applicable to the generation portion of energy charges, and, for primary customers, 2.22 percent and 2.23 percent discount for on-peak marginal costs, respectively.

Tables D-1 and D-2 display the discounts by rate group, charge type and service voltage level.

***Table D-1
Primary Voltage
Discounts By Rate Group & Charge Type***

Rate Group	Peak Demand (\$/kW)	Time Related Demand (\$/kW)				Energy (\$/kWh)	
	Distribution	Distribution		Generation		Distribution	Generation
		Summer	Winter	Summer	Winter		
TOU-GS-1	-	-	-	-	-	0.00166	0.00163
TOU-GS-2	0.30	0.25	0.07	0.27	0.27	0.00029	0.00132
TOU-GS-3	0.37	0.28	0.07	0.30	0.30	0.00024	0.00132
TOU-PA-2	0.21	0.08	0.00	0.23	0.23	0.00032	0.00134
TOU-PA-3	0.31	0.09	0.00	0.32	0.32	0.00028	0.00134

***Table D-2
Subtransmission Voltage
Discounts By Rate Group & Charge Type***

Rate Group	Peak Demand (\$/kW)	Time Related Demand (\$/kW)				Energy (\$/kWh)	
	Distribution	Distribution		Generation		Distribution	Generation
		Summer	Winter	Summer	Winter		
TOU-GS-1	-	-	-	-	-	0.02934	0.00353
TOU-GS-2	6.24	3.48	0.91	0.62	0.24	0.00405	0.00286
TOU-GS-3	7.50	3.83	1.02	0.70	0.29	0.00329	0.00286
TOU-PA-2	3.97	1.05	0.00	0.54	0.25	0.00450	0.00290
TOU-PA-3	6.01	1.30	0.00	0.74	0.34	0.00392	0.00289

Appendix E

Master-Meter Rate Adjustments

Summary

This appendix outlines the background, data and methodologies used to determine the sub-metering discount and the diversity adjustments found in SCE's master-metered domestic rate schedules. This appendix is divided into two sections. The background section provides a brief historical overview of the issues. The analysis section explains the methodologies use to calculate the sub-metering discount and diversity adjustment.

Background

Prior to 1977, all master-metered customers were served under Schedule DM. Schedule DM was introduced in 1954 for general domestic and household purposes in a multi-family accommodation on a single premise served through a single meter. Schedule DM applied to all master-metered accounts until 1977, when the MillerWarren- Lifeline Act (Lifeline Act) went into effect. The Lifeline Act directed the Commission to establish a lifeline quantity of gas and electricity necessary to supply the minimum energy needs of the average residential user. As a result, in January 1977, the Commission split Schedule DM into two schedules: DM and DMS. Schedule DM included all existing multi-family accommodations that were not separately sub-metered.¹⁷⁸ The new Schedule DMS applied to all sub-metered multi-family accommodations including mobile home parks.

Schedules DM and DMS were closed to new installations by the Commission on June 13, 1978. To promote conservation, SCE was ordered to separately meter all new multi-family accommodations.¹⁷⁹ However, a manufacturer of sub-meters filed a petition with the Commission, asserting, among other things, that there was no evidence that individual metering by the utility encourages conservation. After consideration of the petition, the Commission determined that sub-metering by the developer could be provided to new multi-family accommodations in lieu of individual metering by the utilities. As a result, Schedule DMS was again made available to new sub-metered installations in April 1979. On June 5, 1980, Schedule DMS was bifurcated into Schedules DMS-1 and DMS-2. Schedule DMS-2 was made applicable only to mobile home parks, while Schedule DMS-1 was

¹⁷⁸ See D.86087, pp. 46-48 and Appendix C.

¹⁷⁹ See D.90062, p. 9.

made available to all other sub-metered installations. On December 7, 1981, Schedule DMS-1 was closed to new installations, while Schedule DMS-2 was left open to both new and existing mobile home parks.¹⁸⁰ Schedule DMS-2 was subsequently closed to new mobile home parks and manufactured housing communities where construction commenced after January 1, 1997.

In SCE's 1985 GRC, the Commission ordered that residential hotels be eligible for baseline allowances. As a result, the applicability of Schedule DM was modified to include residential hotels on January 14, 1986. The applicability of Schedule DM was expanded in 1988 to include qualifying recreational vehicle (RV) parks, pursuant to Decision D.8809025. In SCE's 1992 GRC, the Commission ordered that Schedule DMS-3 be created to allow Qualifying RV Parks to provide sub-metered service to prepaid month-to-month tenants.

In March 2003, the Commission initiated investigation and rulemaking proceedings (R.03-03-017/I.03-03-018) to address issues relating to the sub-metering discount for mobile home parks. The principal issue in these proceedings was the methodology to determine the sub-metering discount. SCE proposed a methodology based on the marginal costs of service as determined in the utilities' GRCs, which the Commission deemed acceptable.¹⁸¹

In its 2015 GRC Phase 2 proceeding, SCE based the sub-metering discount on the marginal customer costs as filed in that proceeding. In settlement discussions, parties agreed to a methodology for determining the Diversity Benefits Adjustment (DBA)¹⁸² upon initial implementation of rates in the proceeding.

In its 2021 GRC Phase 2 proceeding, SCE based the sub-metering discount on the marginal customer costs as filed in that proceeding. As a result of settlement discussions, parties agreed in its next GRC Phase 2 application, SCE would (1) include a proposal to calculate and collect a DBA from customers served on Schedule DMS-3 and (2) use single family underground costs as the starting point for calculating the sub-metering discount in that proceeding.

¹⁸⁰ D.93586, pp. 57-58.

¹⁸¹ D.04-11-033, OP 7.

¹⁸² Residential and Small Commercial Rate Design Settlement Agreement (A.14-06-014): p. A-11.

In this proceeding, SCE again proposes a sub-metering discount based on marginal costs. The diversity adjustment is based on the methodology established in the 2012 GRC. Additionally, SCE is proposing to collect a DBA from DMS-3 customers and to use single family underground costs in calculating the sub-metering discount.

Analysis

Diversity Adjustment

A. Purpose

The purpose of the diversity adjustment is to adjust the customer's bill to recognize that a benefit is realized by a master-metered customer who had more sales billed at the lower tiered rates and less at higher tiered rates than were actually used by its sub-metered customers. Take for example a master-metered customer that has two tenants, each of whom have a baseline allocation of 200 kWh. The park (SCE's customer) as a whole would have a baseline allocation of 400 kWh, and one park resident uses 205 kWh and the other tenant uses 195 kWh. The park would bill the first tenant for 200 kWh of usage at the baseline rate, and for 5 kWh of usage at a higher tiered rate. The park would bill the second tenant for 195 kWh of usage at the baseline rate. However, SCE would bill the master-metered customer for 400 kWh of aggregate baseline usage at the lower baseline rate.

B. Background

The Commission first addressed the need for a diversity adjustment in PG&E's 1987 GRC. In that proceeding, the Commission found that a diversity adjustment was necessary to correct the inequity in the billing of sub-metered tenants.¹⁸³

In SCE's 1988 GRC, SCE based its proposed diversity adjustment for schedule DMS-2 on a study of the total population of individually metered mobile home customers. SCE believed the methodology it utilized provided the best available approximation of the usage characteristics of sub-metered mobile homes and reflected the diversity for this group as a whole and not the diversity of any one mobile home park. However, the Western Manufactured Housing Communities Association

¹⁸³ D.86-12-091, p. 35.

(WMA) requested that no diversity adjustment be made until SCE performed a study of usage patterns within mobile home parks similar to the study required for PG&E. WMA stated that if the Commission determined that a diversity adjustment was necessary, the Commission should base the diversity adjustment on WMA's data from 29 sub-metered parks and the baseline allowances adopted in the 1988 GRC. The Commission adopted WMA's diversity adjustment proposal, and ordered SCE to prepare a new diversity study for its next GRC.¹⁸⁴

In SCE's 1992 GRC, the Commission adopted SCE's diversity study results, which were based on a sample of 80 apartment sites for Schedules DM and DMS. The Schedule DMS-2 diversity adjustment was based on a random sample of 37 individually metered mobile home parks.¹⁸⁵

In 2010, SCE constructed a new sample of directly metered mobile home parks in conjunction with WMA and their consultant, Freeman Sullivan & Co.¹⁸⁶ The purpose of this new sample was to provide a larger and more representative sample than has been used to date. Currently, the new sample contains 219 mobile home parks with common area accounts for 154 parks. Initially, the sample was constructed using information from SCE's customer databases and mobile home park data provided by WMA. The final sample of directly metered mobile home parks is larger and more recent than samples used in previous studies and provides a better approximation of the DMS-2 population.

¹⁸⁴ D.87-12-066, p. 298.

¹⁸⁵ D.92-06-020, p. 122.

¹⁸⁶ WMA provided a list of mobile home parks that were in zip codes in SCE's service territory along with the addresses of these parks. The master-metered parks were removed, and the remainder provided the starting point for the new sample. From this starting point, 385 parks were located in SCE's service territory and sent to Freeman Sullivan & Co. for verification. Of the 385 parks, 166 were rejected because the number of units indicated in the billing system did not match with the verification results provided by Freeman Sullivan.

C. Diversity Adjustment for Schedules DM

SCE proposes to use the diversity adjustment factors for Schedules DM authorized by the Commission in the Joint Recommendation of SCE and WMA¹⁸⁷ adjusted for the changes for the DMS-2 schedule proposed in this filing.

D. Diversity Adjustment for Schedule DMS-2

SCE proposes to continue utilizing the new sample of 219 individually metered mobile home parks and the methodology to apply a stratification process that accounts for the size, location and average tenant usage of the parks as developed in the 2012 GRC.¹⁸⁸ Further, in the past, the diversity benefit adjustment calculations have relied on one year of recorded data for the calculation. SCE is now using three years of recorded data to minimize weather fluctuations.

E. Diversity Adjustment for Schedules DMS-3

SCE proposes to use the diversity adjustment factors for Schedules DMS-3 authorized by the Commission in the Joint Recommendation of SCE and WMA¹⁸⁹ adjusted for the changes for the DMS-2 schedule proposed in this filing.

1. Data

To provide an accurate representation of the mobile home parks' actual electricity usage, the actual billing data for the approximately 26,186 spaces in the 218 selected parks were used. For instance, a customer with electric service for six months was included in the study for that period of time. The common area usage is based on the TOU-GS-1 account(s) associated with a park. For those parks with no TOU-GS-1 accounts, no common area assumption was made. For the master-metered accounts, the common area bills are calculated at the domestic rate.

¹⁸⁷ 1994 Rate Design Window proceeding, Master-Meter Adjustment Phase, D.95-09-015, Appendix B.

¹⁸⁸ The stratification process places a sample park in one of 12 strata. The strata are defined as parks with CARE customers comprising 40 percent or less of the tenants and parks with CARE customers comprising more than 40 percent of the tenants, average tenant usage below 400 kWh and over 400 kWh, and which baseline region (zone) a park is in. Since there are not sample parks for every baseline region, the regions were collapsed. Regions 5, 6 and 8 were merged and this consolidated region was designated as Coastal; regions 9 and 10 were merged and the consolidated region was designated as Inland; and, regions 13, 14, 15 and 16 were merged creating the Desert region.

¹⁸⁹ 1994 Rate Design Window proceeding, Master-Meter Adjustment Phase, D.95-09-015, Appendix B.

2. Methodology

SCE performed its analysis with monthly kWh usage for the period of April 1, 2018 through March 31, 2021. This data represents load for the same spaces, but not necessarily the same customers. The use of multiple years limits the impact of weather variations.

Using the data from the individually metered mobile home park spaces, individual bills were calculated based on both the tiered rate structure in effect as of June 1, 2020, as well as what SCE proposed in D.16-06-029. The sum of these individual bills reflects the total amount of revenue that a master-metered customer would have received from these accounts had they been sub-metered. Master-metered bills for each park for the same period are also calculated. The base diversity factor for each stratum is determined by taking the difference of the sum of individual bills by the master-metered bill. After strata-wide diversity adjustments are calculated, a weighted average of the strata-wide diversity adjustments is calculated using the weights based on the DMS-2 population in each strata that is determined by average kWh usage, CARE customer composition within each park, and baseline region.¹⁹⁰

The diversity adjustment is sensitive to the tier differential and the baseline allocation. Larger tier differentials result in a higher diversity adjustment. As the baseline allocation increases, the diversity adjustment increases, peaks, and then decreases.

Sub-metering Discount

A. Purpose

The purpose of the sub-metering discount is to reduce the domestic rate charged to master-metered customers to allow them to recover the reasonable cost of providing sub-metered service to their tenants. By law, the maximum allowable discount is the average cost the utility would incur to provide the sub-metering service.¹⁹¹

B. Background

¹⁹⁰ In the 2012 GRC Settlement Agreement, an alternative weighting methodology was adopted that corrects for over/under sampling of the sample relative to the population of the DMS-2 parks. See D.13-03-031, Attachment B, pp. 9-10.

¹⁹¹ Public Utilities Code Section 739.5.

Public Utilities Code Section 739.5 requires the Commission to deduct the average cost of providing service to sub-metered customers from the monthly bill of the master-metered customers:

The Commission shall require the corporation furnishing service to the master-meter customer to establish uniform rates for master-meter service at a level which will provide a sufficient differential to cover the reasonable average costs to master-meter customers of providing sub-meter service, except that these costs shall not exceed the average cost the corporation would have incurred in providing comparable services directly to the users of the service.¹⁹²

The master-metered discount, as defined by the Commission, is the sum of three separate components: (1) cost of service, (2) line loss (including energy theft) adjustment, and (3) diversity adjustment. The cost of service and line loss portions make up the sub-metering discount.

For the cost of service and line loss components, SCE proposes to use the marginal customer costs for domestic customers included in GRC proceedings. These costs include both capital and O&M, based on SCE's most recent cost data. This methodology has been adopted in D.04-11-033, the decision in OII/OIR 03-03-018(017), the Commission's own motion to re-examine sub-metering issues. It is important to note that SCE bases its marginal customer costs on the "rental value" methodology. Should the Commission adopt marginal customer costs based on an alternative method in this proceeding, it is important that the cost of service portion of the sub-metering discount still be based on SCE's rental value method as provided in this filing. The reason for this is that master-metering customers cannot recover their costs from any other customer groups, so the discount must provide these customers with a reasonable opportunity to recover costs from their tenants. For a utility, to the extent a given cost methodology underestimates some of the marginal costs used for revenue allocation, one group of customers simply subsidizes another through the revenue allocation process so that the utility recovers its revenue requirement in total. The proposed submetering discount for DMS-2 are shown in Table E-1 below along with the Diversity Adjustments for DM and DMS-2. Table E-2 shows the results of the calculation to determine the Diversity Benefit Adjustment at both the monthly and daily level (the column denoted as Ratio).

¹⁹² *Id.*

Table E-1
Present and Proposed Master-Meter Adjustments

Line No.	Rate Schedule	Adjustments	2021 GRC Settlement Daily \$/Space	Proposed Rate Daily \$/Space
1	DM	Diversity	-0.094	-0.073
2				
3	DMS-1	Diversity	-0.084	-0.073
4		Discount: Cost of Service	0.085	0.118
5		Line Loss	0	0
6		Energy Theft	0	0
7		Basic Charge	-0.024	-0.024
8				
9		Total Discount	-0.0227	0.022
10				
11	DMS-2	Diversity	-0.084	-0.073
12		Discount: Cost of Service	0.303	0.420
13		Line Loss	0.006	0.006
14		Energy Theft	0	0
15		Basic Charge	-0.024	-0.024
16				
17		Total Discount	0.201	0.329
18				
19	DMS-3	Diversity	0.000	-0.073
20	DMS-3	Basic Charge	-0.024	-0.024
21				
22		Total Discount	-0.024	-0.097

Note: The basic charge listed is the non-CARE basic charge however, if a tenant is on the CARE rate then the CARE basic charge will be used.

Table E-2
Weighted DMS-2 Diversity Adjustment
Using April 2018 – March 2021 Data

Ratio Analysis						
Proposed						
Numerator	Denominator	N	Ratio	Std Err	95% CL for Ratio	
Monthly Total Diversity Adjustment per space	Units	7839	2.209	0.071448	2.069	2.349
Daily Total Diversity Adjustment per space	Units	n/a	0.073	n/a	0.069	0.078

Note: to go from monthly to daily, divide by 30.417

Appendix F

Streetlight Non-Allocated Revenue Requirement

SCE maintains the Net-Plant-In-Service methodology to arrive at the non-allocated streetlight revenue requirement.¹⁹³ The non-allocated streetlight revenue requirement has been set at \$105.492 million, which includes adjustments to account for 1) payments collected from LS-1 customers who have enrolled in the Option E rate, and 2) repair deductions attributable to streetlight assets. The non-allocated streetlight revenue requirement is then allocated across all streetlight customers, by fixture and by wattage, based upon the marginal costs calculated from replacing and maintaining each type of light configuration in SCE's streetlight system.

Adjustments for Option E: The forecast non-allocated streetlight revenue requirement is adjusted to account for payments collected from LS-1 customers who have enrolled in the Option E rate for their LED conversions. The charge that LS-1 Option E customers must pay for is updated with the accounting inventory of lamps in service during the filing of each GRC Phase 2 proceeding. These assumptions include depreciation, taxes (*i.e.*, federal, state, and property), life of lamps (*i.e.*, 20 years), return of capital investments, and value of investments. The number of LED lamps that are forecasted for the test year is then multiplied by the charge that is currently in effect. The product is then removed from the non-allocated streetlight revenue requirement that is forecasted for the test year.

Adjustments for Taxes: The forecast non-allocated streetlight revenue requirement is adjusted to account for the portion of repair deductions included in the 2025 GRC Phase 1 proceeding attributable to streetlight assets.

¹⁹³ Pursuant to the methodology developed through a settlement agreement adopted in SCE's 2012 GRC Phase 2 and continued thereafter.

Table F-1
Streetlights | 2025 – 2028 Forecast Summary of Earnings

Summary of Earnings		Forecast	Forecast	Forecast	Forecast
Line	Description	2025	2026	2027	2028
1.	Operating Revenues	116,232	116,927	117,676	118,589
2.	Operating Expenses				
3.	O&M	5,938	6,070	6,209	6,355
4.	Franchise Requirements	1,080	1,087	1,094	1,102
5.	Total Operating Expenses	7,018	7,157	7,303	7,457
6.	Depreciation	36,069	36,618	37,158	37,697
7.	Taxes Other Than On Income	9,581	9,750	9,802	9,836
8.	Taxes Based On Income	15,526	15,439	15,523	15,788
9.	Total Taxes	25,107	25,188	25,325	25,624
10.	Total Operating Expenses	68,194	68,963	69,786	70,777
11.	Net Operating Revenue	48,039	47,964	47,889	47,811
12.	Rate Base (Weighted Average)	645,861	644,870	643,875	642,827
13.	Rate of Return	7.44%	7.44%	7.44%	7.44%

Table F-2
Streetlights | 2025 Adjusted Non-Allocated Revenue Requirement

Summary of Earnings		Forecast
Line	Description	2025
1.	Base Revenue Requirement	116,232
2.	Tax Adjustment	(1,810)
3.	Option E Adjustment	(8,930)
4.	Adjusted Non-Allocated Revenue Requirement	105,492

Appendix G

Decomposition of Distribution & Generation Costs by Rate Component

Figure G-1
Illustrative Decomposition of Distribution Costs by Rate Component

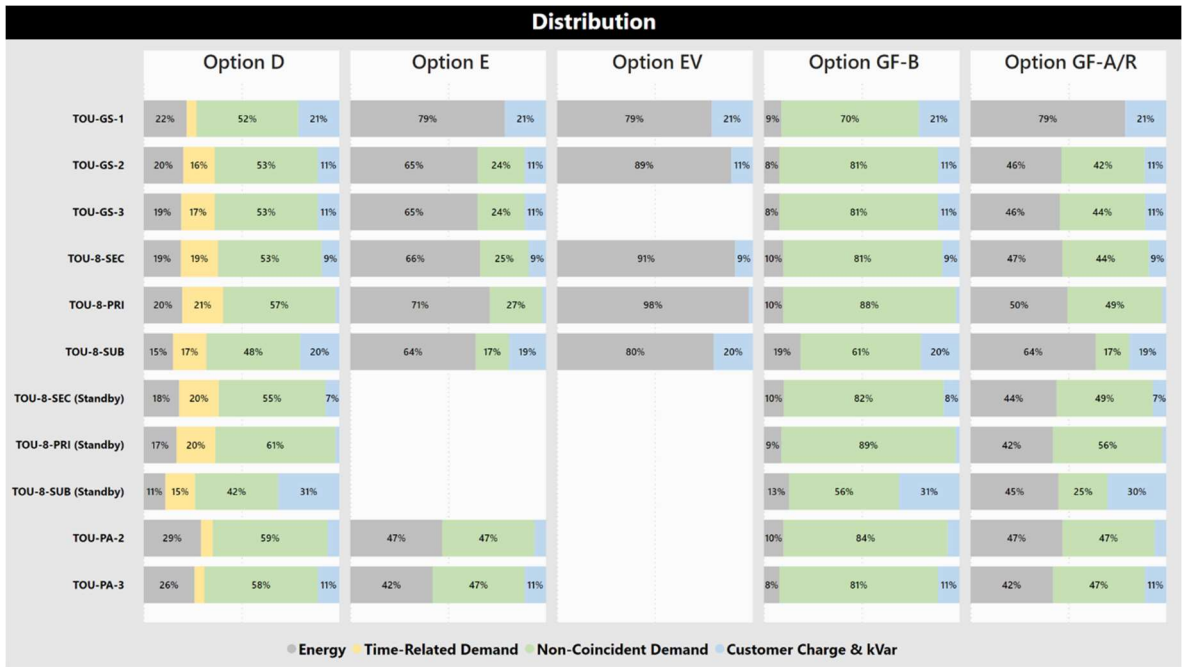
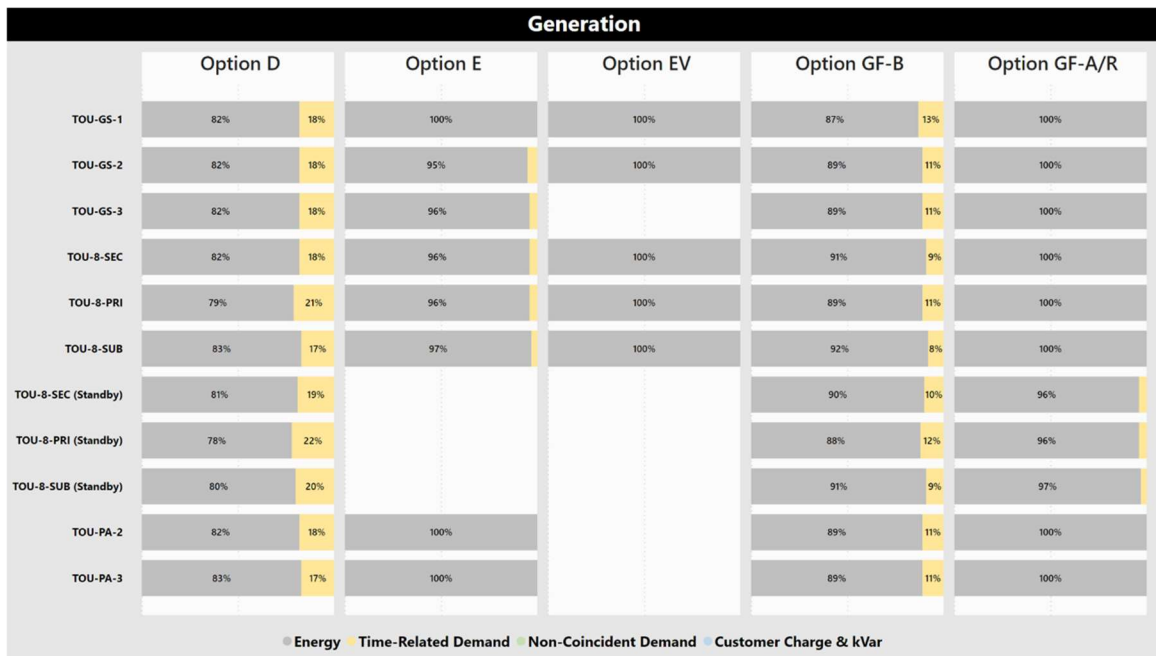


Figure G-2
Illustrative Decomposition of Generation Costs by Rate Component



Appendix H

Dimmable Streetlight Pilot Study

Dimmable Streetlight Pilot Study

In this appendix, SCE presents results of its dimmable streetlight pilot study, which was initiated to examine the potential benefits of smart and communicating streetlight photo sensors for both LS-1 and LS-2 customers. The pilot was comprised of two phases: Phase 1 focused on internal evaluation of dimmable streetlight hardware and explored the development of an interface for customer billing. Phase 2 focused on testing of the technology and refinement of the interface for data integration, billing, and outage identification. ¹⁹⁴

SCE specifically wanted to investigate if smart street light sensors could provide a full view and operational platform for streetlights including near real time outage reporting, utility grade metering, and control functions including dimming or brightening of streetlights operations. SCE's pilot sought to better understand how effectively the sensors assisted in undertaking several utility operations:

- Provision of near real-time outage notifications and related information
- Ability to create and provide utility grade metering data
- Enactment of control functions (dimming or brightening), which could help facilitate demand response activities or control street lights in alignment with requests from local government customers
- Through metering capabilities, be a “gateway” for smart community technology attachments or applications as often requested by local government customers

At a high level, the sensors as deployed in the field, proved to be robust and operationally reliable. SCE tested both GE and Itron smart sensors as part of this pilot and completed meter testing on both technologies. Both manufacturers performed well in the field and the manufacturer data points towards a successful outcome in the destructive testing phase as well.

SCE deployed roughly 12,000 sensors in various geographic locations around the SCE territory to aid in the development of a deeper understanding of the capabilities, performance, strengths, and

¹⁹⁴ As stated in Section VII.H, SCE does not recommend adoption of the proposed rate under a broader tariff-based rate schedule and will explore the pilot(s) to vet the feasibility of integrating customer owned metering and data systems with SCE's own metering and billing system.

weaknesses of the devices. Each of the two manufacturer technologies were successfully used to test outage and informational metrics:

- Both GE and Itron sensors passed SCE meter testing showing that both were capable of providing utility grade meter information. This metric and capability could open the door to a future metered street light rate for both SCE and customer owned street lights in the future, or possibly demand response or other technology opportunities.
- Control functions which were also demonstrated could also help facilitate potential demand response activities or other energy efficiency opportunities as lighting systems come more into focus around the electric system peak shifting to evening hours.

Locations

SCE coordinated with LS-1 Option E implementations in certain communities to lower the cost of installation and avoid “second truck rolls” for the specific purpose of installing smart and communicating street light sensors. A total of 12,610 SCE owned demonstration devices were installed in the following communities:

- Compton
- Inglewood
- Irwindale
- Ridgecrest (Itron)
- Barstow
- Temecula (both LS-1 and LS-2 devices are deployed in Temecula)
- South Pasadena

Roughly 20 percent of the devices utilize cellular technology to communicate while the remainder transmit and carry data via mesh network nodes (similar to SCE’s existing Smart Connect Metering system). An important aspect of this demonstration was to consider that a potential future deployment may be tied closely to the next generation of AMI meters and could play a role in enhancing the mesh network associated with future meters and technology.

Findings

The sensors proved to be robust and reliable in the field with one notable exception of 48 faulty units that were discovered soon after the Barstow implementation. The units were returned to GE for testing after which they were reported to be an anomalous small group with a manufacturer error – it is suspected that the heat and more extreme conditions in Barstow may have caused this small “batch” defect to show-up more quickly than might otherwise have been experienced.

SCE meter testing confirmed that the GE and Itron units were capable of providing utility grade metering data. While there would be significant work to be completed around integration of that data and the secure delivery of data into utility systems in efficient and secure ways, the units were capable of providing utility grade meter information and data. Destructive testing of the smart sensors confirmed that the units are robust and meet utility requirements for both reliability and durability. Email notifications of outages proved to be successful with “near real time” notifications being received via email notification consistently. Future implementations of the technology could potentially integrate and more “direct” path to outage notification providing a more seamless notification procedure and trouble ticket submittal. SCE was also able to determine if the outage was fixture related or something more in-depth such as an underground service failure. This “troubleshooting” capability could prove valuable information in the future to dispatch the “right” technicians to a reported outage.

Although SCE placed an initial expectation and high value around the sensor’s ability to provide outage notifications, the impact of SCE’s steady LED replacement program negatively impacted the overall value (currently) of the outage notification feature of the sensors. Given the significant number of LED replacements in the SCE territory, that value proposition may be best considered as part of the broader next generation AMI technology implementation effort. It should be noted that SCE has now replaced over 320,000 street lights with LED fixtures over the past six to seven years, which has reduced street light outages dramatically given new long lasting and efficient LED fixtures.

One concern expressed by customers was caution about dimming street lights without a proper study and review to ensure that light levels met minimum standards at the street surface. SCE did not collaborate with communities to conduct in-depth engineering analysis to ensure light levels could meet local government standards for the purposes of the sensor demonstration project. Limited testing was

undertaken and completed around the dimming capability of the devices during “daylight” hours and SCE found that the technology could provide dimming capabilities for potential energy efficiency or demand response activities. SCE operated a small number of lights in each community during daylight hours and adjusted the brightness of the lights down, noting the decreased energy usage as a marker that the light levels were in fact changing. For this particular aspect of the technology to be successful in the future, local government customers would need to be comfortable and acknowledge a willingness to experience decreased lighting levels during specific and agreed upon night time hours. Because the lights were not dimmed during normal operation during overnight hours, customers were not placed on midnight service as originally contemplated, as there was no reduction of energy usage given the full overnight operation of the lights throughout the pilot. This technology may be considered as part of the next generation of advanced metering technology, so no further pilot activities are anticipated as associated with the deployed smart sensors and affiliated equipment.

As a stand-alone technology, the cost remains high with sensors still commanding roughly \$150 to \$200 per street light (installed cost). These costs also do not consider full integration of the technology into utility systems to optimize metered data or operational integration. With roughly 450,000 total street lights with the potential to be integrated into a smart sensor system, the costs would be significant as a stand-alone project.

Conclusion

The sensors proved to be a viable and robust technology that transmit operational and metering data as expected and can function as control devices. While there would certainly be significant work to integrate the data into various operational or metering systems, the devices proved that they communicate outages in a timely and accurate fashion, function well in diverse geographic locations and in harsh weather conditions and demonstrated reliability through operational “destructive testing” at the SCE meter test facility. The data from the sensors meet SCE and utility standards to provide reliable meter and usage data.

SCE may consider a proposal in the future, and if so, will propose a metered rate specific to street lights that could facilitate opportunities like smart community technology deployment. The metered rate

could also facilitate demand response activities knowing that the utility peak demand is now in the early evening hours when street lights are operational (must overcome safety and light level requirement concerns). In the meantime, SCE will continue to explore this opportunity. For this technology to be effective and deployable in the future, it must coordinate and be aligned with the broader metering and technology systems being contemplated under SCE's AMI 2.0 effort.

Appendix I

Distributed Energy Resources (DER) Study

Introduction

During the winter of 2021, SCE and members of the Medium and Large Power Rate Group engaged in settlement discussions around rate design, cost treatment, and/or the class treatment of customers who adopt Distributed Energy Resources (DER customers). Specifically, these parties had expressed concerns over the potential of cost-shift between high load factor and low load factor customers considering SCE's design criteria and structure for the DER rate option in the respective classes, namely Rate Schedule Option-E. Discussions during settlements led SCE and parties to develop a framework to study the class treatment of DER customers by using generally adopted methods used in the determination of marginal cost, revenue allocation and rate design. This framework was formalized and became part of the Motion filed by SCE and Settling Parties for adoption of Medium and Large Power Rate Group Rate Design Settlement Agreement, which was filed on February 18, 2022.

On August 4, 2022, the Commission adopted the Medium and Large Power Rate Group Rate Design Settlement Agreement, in which settling parties agreed to an attrition year DER-as-a-Class Study (Study). The Study required SCE, in collaboration with settling parties, to explore the potential of creating a separate DER customer class. This study was scoped to explore the following items: 1) types of customers or services that should be part of the DER class, 2) customer size thresholds that may apply to the DER class, and 3) the cost to serve DER customers. The objectives of the study included:

2. Evaluate benefits of DER customers as a separate class. This evaluation may also consider if customers with similar load characteristics (i.e., those with load factors or hourly usage profiles, and kW demands similar to DER customers) should also be grouped within the separate class;
3. Determine which service options (i.e., EV, Option E, RTP, others) should be included in a DER rate class;
4. Study overall benefits of revenue allocation and rate design impacts associated with customers under the separate rate class treatment using the 2021 GRC Phase 2 costs and load studies, adjusted to reflect separate DER class(es), as the basis for the study; and
5. Align the study with applicable Commission's DER Action Plan 2.0 Vision Elements.

On September 29, 2022, SCE initiated its DER Class Study working group and discussed the objectives and considerations of this study. SCE formed a working group of interested parties, including CLASSA (California Solar Storage Association), CLECA (California Large Energy Consumers Association), CMTA (California Manufacturers & Technology Association), DACC (Direct Access Customer Coalition), EPUC (Energy Producers and Users Coalition), EUF (Energy Users Forum), EVgo Services, LLC, FEA (Federal Executive Agencies), JARP (Joint Advanced Rate Parties), PAO (Public Advocates Office), SBUA (Small Business Utility Advocates), SEIA (Solar Energy Industries Association), and Tesla, Inc. The goal of the working group aligned with basic elements discussed above as the Study's objectives and to provide feedback on the analysis, the data used, and results obtained.

The Working Group study concluded on February 22, 2024. At the conclusion of the Study, SCE determined that current levels of DER adoption in the different consumer groups needed more time to mature and that with relatively low adoption levels, the costs-to-serve analysis can have limited inferential value. SCE therefore concluded that it is not appropriate to create a separate DER class in this Application, but that it should continue to study the different subcategories of customers and their respective cost-to-serve in subsequent GRC Applications.

The Definition of DER in the Ratemaking Process

To determine if a separate DER rate class would be beneficial, SCE first looked to define what SCE would include as a DER and what would be excluded, even if the technology existed within the general category of a 'Distributed Energy Resource'. This included examining what major institutions have used as a definition, applying which of these is relevant for a cost to serve study, and a brief description of other elements and why they have been excluded in this analysis.

The generally accepted range of DER solutions are:

1. Transportation Electrification (TE)
2. Solar or Photovoltaic Systems (PV)
3. Wind
4. Combined Heat and Power (CHP) or 'cogeneration.'

5. Energy Efficiency (EE)
6. Demand Response (DR)
7. Microgrids
8. Energy Storage / Batteries

Each of the DER solutions listed above comes with its own unique considerations and forms an important part of the larger ecosystem necessary for accomplishing electrification and achieving the State’s decarbonization goals. For this study, SCE identified TE, PV, and Energy Storage as a primary subset of DER solutions that should be directly counted for assessment in the Study.

SCE considered various definitions for a “DER”, including the CPUC’s definition, which states that; *“Distributed energy resources include rooftop solar and other distributed **renewable** generation resources, energy storage, electric vehicles, time variant and dynamic electric rates, flexible load management, demand response, and energy efficiency technologies.”* The New York Public Service Commission, which regulates all regional electric, gas, steam and water utilities has adopted the following definition: *“Distributed Energy Resources (DER) is used in this context to include Energy Efficiency (EE), Demand Response (DR), and Distributed Generation (DG).¹⁹⁵”* The National Renewable Energy Laboratory (NREL) defines a DER as *“small, modular, energy generation and storage technologies that provide electric capacity or energy where you need it. Typically producing less than 10 MW of power, DER systems can usually be sized to meet your particular needs and installed on site.”* Finally, the Electric Power Research Institute (EPRI)¹⁹⁶ defines a DER as an electricity supply source that fulfills the first criterion, and one of the second, third or fourth criteria listed below:

1. Interconnected to the electric grid, in an approved manner, at or below IEEE medium voltage (69 kV).
2. Generate electricity using any primary fuel source.

¹⁹⁵ NARUC Manual at p. 43, pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0?_gl=1*19wewkh*_ga*MjAwNTAwMTc4Ny4xNjc3NzA0ODU5*_ga_QLH1N3Q1NF*MTY3NzcwNDg1OC4xLjAuMTY3NzcwNDg1OC4wLjAuMA.

¹⁹⁶ NARUC Manual at p. 44, pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0?_gl=1*19wewkh*_ga*MjAwNTAwMTc4Ny4xNjc3NzA0ODU5*_ga_QLH1N3Q1NF*MTY3NzcwNDg1OC4xLjAuMTY3NzcwNDg1OC4wLjAuMA.

3. Store energy and can supply electricity to the grid from that reservoir.
4. Involve load changes undertaken by end-use (retail) customers specifically in response to price or other inducements or arrangements.”

In the initial series of working group meetings, the Working Group engaged in constructive discussions, leading to a consensus on the subcategories of customers that would be included in the Study – parties agreed to include customers on rate Option-E with no behind-the-meter resource, NEM, Paired Storage, Standalone Storage, and TE rate options, while specifically excluding customers on Standby rate schedules and RTP rate schedules. Additionally, Demand Response and Energy Efficiency were also excluded as considerations for those programs are typically outside the scope of the typical elements of rate design and revenue allocation included in Phase 2 of SCE’s GRC.

While, the Working Group deliberated the merits of including Option-E customers who do not adopt behind-the-meter technologies in the Study, it was noted that the cost disposition for that subcategory of customers was the primary reason parties involved in the Medium and Large Power Rate Design settlement discussions initiated a request for the Study in the first place— essentially some parties wanted to perform a review to assess whether Option-E customers impose different costs in comparison to the remaining subcategories of customers who adopt behind-the-meter resources, as well as a typical customer who can generally be considered a non-adopter. Some parties deliberated that Option-E customers who do not adopt behind-the meter technologies like customers on NEM rate schedules, with EVs, or with storage, should not be classified as DER customers and therefore excluded from the analysis. To gain traction on this deliberation, the Working Group agreed to examine and compare load characteristics, particularly the load factors and consumption patterns for the various DER sub-categories including Option-E customers with no behind-the-meter resources, hereon described as Option-E (NONTech). In assessing load factors and consumption profiles, SCE found that the Option E (NONTech) subcategory of customers, customers on NEM, and customers with EVs typically have lower load factors than the other sub-categories of customers, and their load profiles appear comparable to customers who adopt behind-the-meter resources. In conclusion, the Working Group decided to include Option-E (NONTech) customers and assess SCE’s cost

to serve those customers in comparison to the remaining subcategories of adopters and non-adopters as part of the Study.

As part of scope development, parties also agreed to exclude RTP customers from the DER subcategory of customers – because RTP rates directly translate underlying hourly marginal costs into hourly prices for each consumer group, distinct RTP rate structures for customers classified as DER adopters or non-adopters may not be relevant. In addition, the relatively small number of customers currently enrolled on SCE’s RTP rate schedules were deemed to not have a material impact on the general goals and objectives of the Study. The Working Group therefore unanimously agreed to classify RTP customers within the non-DER subcategory of customers for the Study and acknowledged that Demand Response and Energy Efficiency should be excluded as considerations for those programs are typically outside the scope of the typical elements of rate design and revenue allocation included in Phase 2 of SCE’s GRC.

Lastly, given the scarcity of customers on SCE’s Standby Rate Schedules who adopt technologies like NEM, EV, or storage, the working group agreed to exclude Standby customers from the Study.

Load Analysis: Load Studies and Profile Development

An essential first step in developing a Cost-to-Serve analysis is studying the underlying consumption and demand characteristics, load shapes, and specific usage patterns that may be unique to each subcategory of customers included in the Study. Doing so helps better understand how customer behavior patterns directly translate into how customers add to or help the IOU avoid costs.

SCE segments customers into two broad grouping categories based on specific characteristics: (1) Rate Classes, such as residential, commercial, industrial, or agricultural customers with broad and general differences in their end-use of electricity; and (2) Rate/Consumer Groups that further segment customers based on levels of connected or metered demand with each segment having distinct usage patterns, demand profiles, and load characteristics that can influence their cost of service. For the purposes of this Study, SCE has identified the following rate groups as within scope of this assessment:

1. TOU-GS-2, General Service (Medium Commercial & Industrial); *Greater than 20 kW and up to 200 kW*

2. TOU-GS-3, General Service (Large Power Rate Group); *Greater than 200 kW and up to 500 kW*
3. TOU-PA-2, Agricultural; *Up to 200 kW*
4. TOU-PA-3, Agricultural; *Greater than 200 kW*
5. TOU-8 SUB (Non- Standby); *Greater than 500 kW and served at Sub-transmission Voltages; (Above 50kV)*
6. TOU-8 PRI (Non-Standby), *Greater than 500 kW and served at Primary Distribution Voltages; (2 kV to 50 kV)*
7. TOU-8 SEC (Non-Standby); *Greater than 500 kW and served at Secondary Distribution Voltages; (less than 2 kV)*

In the context of this Study, it is essential to acknowledge that comprehensive projections of DER solutions and adoption of electrification technologies within customer segments can be proprietary, and not fully transparent in the underlying methodology and numerical assumptions that are used to shape individual customer behavior. To avoid creating complexity on top of obfuscation, SCE has elected to use existing customer data and simple, yet defined assumptions, especially when developing DER shapes for consumer groups with few or no existing DER equipment. This allowed for prospectively examining assumptions that were embedded in developing load shapes when new data becomes available. To further cross-validate results from the estimation process, SCE also peer-reviewed assumptions and inputs used in the analysis - this ensured a second degree of vetting in the final load shapes presented to the Working Group.

While customers within each rate/consumer group are categorized into two main subcategories namely non-DER and DER, the DER subcategory was developed as an aggregation of individual subgroups: Option-E (NONTech), NEM ONLY, Paired Storage, Standalone Storage, EV Rate (NONDCFC), and EV Rate (DCFC). In this Study, EV subcategories are defined by customers subscribing to SCE's commercial EV rate schedules, namely TOU-EV-8 and TOU-EV-9, with the subcategories of DCFC and NONDCFC. Using recorded interval data and the number of service accounts from the year 2022, SCE developed hourly load profiles for each subgroup, derived the average customer profile based on the number of accounts in each group, and then used these recorded hourly load profiles (2022), with some modifications, to estimate DER subcategory load profiles based on the forecast of DER adoptions expected in 2025. DER adoption

levels in the year 2025 were also used to determine the estimate of service accounts by DER subcategory in the forecast year for each rate/consumer group. This estimation process helped derive hourly load profiles for each DER subcategory and the DER class level profile for the forecast year 2025. During this process, SCE had to adjust the number of service accounts for non-DER customers under the assumption that DER adoption occurring in a rate/consumer class is mostly enabled by non-adopters adopting some suite of DER solutions, thereby decreasing the total population of non-adopters over time.

Option-E (NONTech): Assuming the relative maturity of the Option-E rate schedule that was implemented in 2019, SCE used a simplifying assumption for the purposes of the Study that customer migration of natural benefiter onto the Option-E rate schedule, who also have not adopted a behind-the-meter DER, has generally stabilized, resulting in no change in the number of customers in the Option-E(NONTech) subcategory between 2022 and 2025.

EV – DCFC and Non-DCFC: In developing the forecasted number of service accounts for EV customers on EV specific rates in 2025, SCE had to make modifications to estimates of account penetration for what seemingly appeared to be an above trend estimate of adoption for that subcategory of customers – given the expected growth in MWhs for that subcategory of customers in 2025, and if 2022 average consumption-per-account on EV specific rates was used, SCE’s estimate of the number of accounts in year 2025 would be somewhat unfeasible. While SCE retained the MWhs in the rate group, adjusting the count of service accounts for the forecast year implies that there may exist some prospective amount of MWhs resulting from transportation electrification that may not materialize on EV specific rates, and that electrification driven MWh growth may more broadly materialize across other subcategories of customers not on EV specific rates in that rate/consumer group. SCE analyzed the numbers of service accounts on EV rates between 2022 and 2024. Using this growth rate, SCE projected the number of accounts on EV rates for 2025. For example;

- The number of accounts on the TOU-EV-8 rate (within TOU-GS-2 rate group) increased from **442 accounts** at the end of 2022; to **531 accounts** in 2024; with SCE projecting **638 accounts** in 2025.

- The number of accounts on the TOU-EV-9 rate (within TOU-8-SEC Non-standby rate group) increased from **146 accounts** at the end of 2022; to **216 accounts** in 2024; with SCE projecting **319 accounts** in 2025.
- SCE's current projections show no EV adoption in the 'agricultural' rate classes for the forecast year 2025.

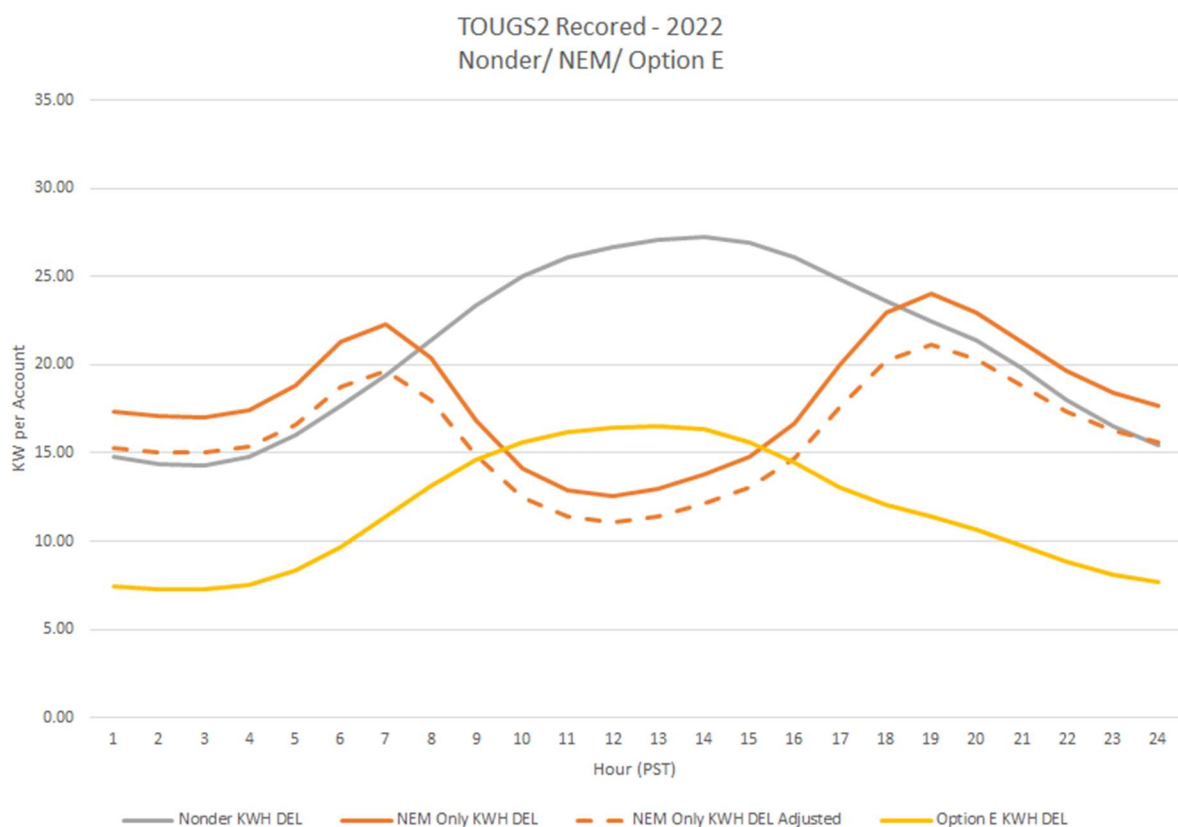
SCE's forecasting process typically estimates TE usage (Gwh) by rate/revenue class - because the relationships between SCE's current classifications of rate classes used for forecasting can diverge from a direct mapping to rate/consumer groups that are used for revenue allocation and rate design, SCE developed a cross-tabulation that maps GWh estimates of EV adoption by revenue class to GWhs by rate/consumer group that were available for the recorded year 2022. This mapping was used as the basis of deriving the rate/consumer group estimate of DER GWhs in the forecast year 2025. Because SCE uses an allocation method when assigning DER GWhs to rate/consumer groups in the forecast year that is based on GWhs in the recorded year, a material concentration of GWhs in the recorded year can materially impact how much GWhs are assigned to the respective rate/consumer group in the forecast year. In examining EV load in the recorded year 2022, SCE found that a sizeable amount of EV GWhs is concentrated in the TOU-8-SEC Non-standby (TOU-EV-9) rate/consumer group, which results in the adjusting the allocation percentage of EV GWhs for this rate group higher for the forecast. For the purposes of this Study, SCE classifies customers subscribing to the TOU-EV-8 rate schedule within the TOU-GS-2 rate/consumer group for both the recorded year 2022, and the forecast year 2025, because SCE uses design elements and the structural construct of TOU-GS-2 rate/consumer group when designing the TOU-EV-8 rate schedule even though the demand classification for eligible customers on the TOU-EV-8 rate schedule spans both TOU-GS-2 (20 kW up to 200 kW) and TOU-GS-3 (200 kW and up to 500 kW). This results in allocating EV GWhs in the forecast year adopters subscribing to SCE's TOU-EV-8 rate schedule being combined into the TOU-GS-2 rate/consumer group.

In summary, SCE aligns the revenue class EV forecast with the rate group EV forecast based on recorded-year load mappings. The allocation to the TOU-8-SEC Non-standby (TOU-EV-9) rate is adjusted upward due to concentrated EV GWhs. Additionally, forecasted EV GWhs from TOU-EV-8 subscribers are

combined into the TOU-GS-2 rate group, considering design elements and structures. This method was used to determine the allocation percentage of the EV forecast among different rate groups. After obtaining the rate groups' annual GWH forecast, the hourly shapes were developed by shaping the annual forecast using the recorded hourly profiles from each rate group. The recorded profiles for EV are divided into two categories: non-DCFC and DCFC. Both profiles are used for calculations. In cases where certain rate groups do not have EV profiles, the EV profiles of similar rate groups are used as proxies. An example would be rate/consumer group TOU-8-SUB Non-standby where the forecast year included 300 GWh of expected EV adoption with no adoption in the recorded year 2022. In that case the recorded year 2022 load profiles of rate/consumer group TOU-8-SEC Non-standby are used as the basis of developing the EV profiles of the forecast year 2025 for rate/consumer group TOU-8-SUB Non-standby.

NEM Load Profiles: After a high-level overview of the forecast methodology, this section will delve into a close examination of the NEM forecast. Using TOU-GS-2 as an example, Figure I-1 illustrates the 2022 recorded profiles for customers considered non-DER (grey line) and customers on NEM (solid orange line). During the morning and evening hours, the load profile of current NEM customers differed from that of non-DER customers as can be seen in the gap between the grey line and the solid orange line in the graph below. To address this, SCE adjusted the NEM profiles to develop an imputed average NEM load profile (dash orange line) by aligning hours 1 to 6 and 19 to 24 to normalize the recorded average NEM profile with the recorded average non-DER profile, and by doing so assumed that on average, a non-DER customer who adopts a behind-the-meter PV resource would essentially have the same average load shape outside of the primary hours when the PV resource was producing power. The aggregate forecast of the NEM (PV) subcategory of DER adopters is determined by adding two components: the recorded NEM load and the incremental NEM load. The latter is calculated by multiplying the anticipated number of newly installed PV in the projected year 2025 with the adjusted NEM load profiles for 2022.

Figure I-1
2022 TOU-GS-2 Customer Load Profiles

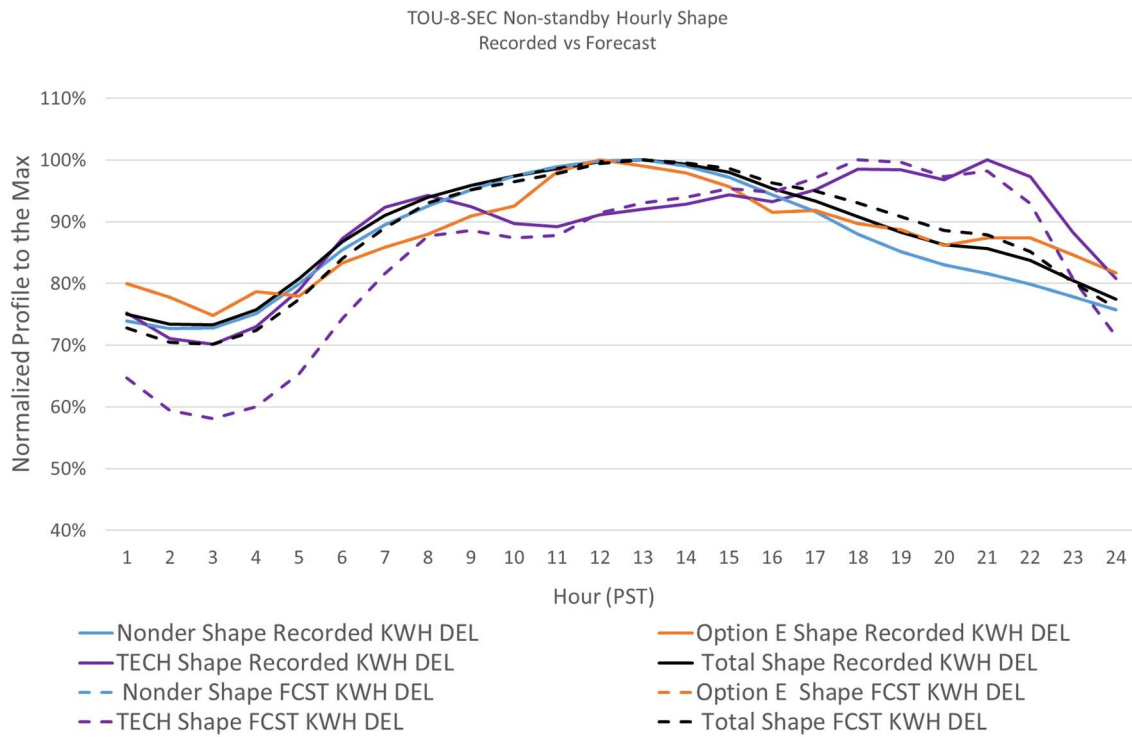


Storage: For the purposes of this Study, SCE categorized storage customers into two subcategories, namely Standalone Storage and Paired Storage. SCE then derived the recorded average profiles for each subcategory for the year 2022. To estimate the aggregate hourly shape in the forecast year for each subcategory, SCE multiplied the forecasted number of storage accounts with the recorded storage profiles developed for each rate/consumer group. For rate/consumer groups where there was no storage penetration in the recorded year 2022, but the forecast year included estimates of storage penetration, SCE used recorded year storage profiles of similar rate groups as the basis for developing the forecast year storage profiles. An example would be rate/consumer group TOU-8-SUB Non-standby where the forecast year included 2 GWh of expected paired storage adoption with no adoption in the recorded year 2022. In that case the recorded year 2022 load profiles of rate/consumer group TOU-8-SEC Non-standby were used as

the basis of developing the paired storage profiles of the forecast year 2025 for rate/consumer group TOU-8-SUB Non-standby.

Once each subcategory of DER adopter's load profile was estimated SCE then developed the forecasted load shapes for the DER Class by aggregating the load profiles of the individual subgroups. Figure I-2 below has the sample output of the hourly shapes for TOU-8-SEC Non-Standby. The Y-axis represents the normalized profile to the max and 100 percent will be the peak of the profile. The blue solid line and blue dash line are the recorded and forecast kWh delivered shapes for non-DER customers. Since the recorded and forecast shapes for non-DER are identical, the two blue lines overlap. The same applies to the Option E shapes in orange. The purple solid line and purple dash line are the recorded and forecast kWh delivered shapes for technology customers including, NEM, storage, and EV. The difference in the recorded and forecast shapes is mainly driven by NEM and EV. The black solid line and black dash line are the recorded and forecast kWh delivered shapes for the whole TOU-8-SEC Non-Standby rate group. At the aggregation level, the differences in the recorded verses forecast shape are insignificant. Additionally, the forecasted load shapes have been developed for rate groups, including TOU-GS-2, TOU-GS-3, TOU-PA-2, TOU-PA-3 and other TOU-8s.

Figure I-2
TOU-8-SEC Nonstandby Recorded (2022) vs. Forecast (2025) Hourly Shape



Cost-To-Serve: Rates Analysis

Purpose

This section describes SCE’s analysis that uses rate/consumer group average marginal cost rates in determining the cost-to-serve each subcategory of adopters and non-adopters in each rate/consumer group. Rate/consumer group average marginal cost rates are developed using the same unit marginal cost and revenue allocation described in exhibit SCE-02 and SCE-03 respectively, and do not include any modifications or adjustments that SCE can adopt when moderating the impact that some rate design elements can have on different consumer groups, or subsets of customers within a rate/consumer group. Group average cost-based rates also do not change the structural mechanism of cost recovery where energy costs are designed for recovery as energy charges and capacity costs are designed for recovery through

coincident or non-coincident demand charges based on the underlying disposition of cost adopted in Exhibit SCE-02.

In this Study, SCE used two bases of cost-derived rates: Marginal Cost Rates and EPMC-Scaled Marginal Cost Rates. It is important to note here that rate elements that do not adopt a marginal cost basis like Transmission rates, non-bypassable charges, and certain rate adders were included at retail rate levels in the cost-derived rate to ensure parity in comparison of bills at the default retail rate and bills at the cost-derived rate - this becomes important when assessing relative contribution-to-margin (CTM), typically expressed as the percent difference between bills on the retail rate and bills on the cost-derived rate, so as not to exaggerate or diminish CTM estimates because of structural and asymmetric inclusions or exclusions of cost components.

Marginal Cost Rates (MC Rates) are derived using revenues allocated through the process and methods described in Exhibit SCE-03, where marginal cost revenue responsibility (MCRR) is calculated by multiplying unit marginal costs described in Exhibit SCE-02 by consumption-based drivers of cost for each cost category. These revenues are then converted into rate/consumer group average marginal cost rates by using the same billing determinants of the forecast year (2025) that SCE used for rate setting in this Application.

EPMC-Scaled Marginal Cost Rates (EPMC-Scaled MC Rates) use the same design and structural elements described above for Marginal Cost Rates but add an equal-percent scalar to the marginal cost of each rate component to achieve revenue neutrality with SCE's retail rate revenues, allocated on a functional basis, to each rate/consumer group.

SCE performs the cost-to-serve rates analysis to determine if customer segments that adopt a specific DER technology/solution; *OR* a unified category that includes a suite of customer subcategories that adopt specific DER technologies/solutions identified in this Study; *OR* customer segments that do not adopt DER technologies, exhibit observable differences in cost-to-serve that may merit treating those customer subcategories or segments differently. Generally, customers who adopt behind-the-meter technologies can use those resources to induce flexibility in consumption (kWh) and their demand (kW) for electricity from the grid in a way that symbiotically moderates their bills in proportion to how much they can moderate costs

to the grid. Average load profiles by customer subcategory discussed in the Load Analysis section were used to derive rate specific determinants for energy (kWh) and demand (kW), that were then used to calculate customer retail bills on SCEs default rate Option-D and develop estimates of SCE's cost-to-serve using both Marginal Cost Rates and EPMC-Scaled Marginal Cost Rates. These calculations were done for each subcategory of DER customers, the aggregate non-DER and DER customer groupings and the rate/consumer group in aggregate – The rate/consumer group aggregate profile used in this Study would represent a weighted composition of DER adopters and non-adopters in each rate/consumer group.

Methodology:

In this analysis, for each consumer group, and subcategory of customers within a consumer group, SCE used three variants of rates - (1) Default Retail Rate Option-D, (2) Marginal Cost Rate, and (3) EPMC-Scaled Marginal Cost Rate, with SCE adopting the definition of cost to serve for this Study based on the EPMC-Scaled Marginal Cost Rate.

By calculating customer bills on three variants of rates, SCE was also able to compute the individual CTM for each category analyzed in the Study using both EPMC-Scaled Marginal Cost Rates and the Marginal Cost Rates, noting that, SCE typically adopts CTM as the percent difference between the Retail Rate and the Marginal Cost Rate – the higher the percent difference, the higher the available margin embedded in the retail rate is in comparison to the marginal cost rate. While CTM analysis is a useful tool, the inference of available margin should be complemented by a sound understanding of revenue and cost composition that is used in the analysis – drawing simplifying conclusions can lead to a sophomoric appreciation of available margin, the converse of which enhances sound investment and valuation decisions. Because this analysis is not an attempt to assess specific optionality that can be extended in the structural design of retail rates, SCE used the default rate Option-D as the basis of calculating each subcategory's contribution-to-margin for each rate/consumer group. Rates developed and used in this study were disaggregated for each underlying cost component so the analyst could assess how changes in customer profiles caused by the adoption of specific DER technologies impacted changes in each underlying component of cost.

In calculating the cost-to-serve SCE first calculated energy (kWh) and demand (kW) determinants for each of the load profiles used in the analysis. Table I-1 below illustrates the differences in annual energy consumption determinants by TOU period for each customer subcategory in the TOU-GS-2 rate/consumer group that was used in this analysis. SCE also shows the corresponding demand determinants for each customer subcategory in the TOU-GS-2 consumer group in Table I-2 and Table I-3. In each table, time-of-use determinants are shown for four months of summer and eight months of winter. The Aggregate DER determinants are based on the average aggregate profile of all DER customer subcategories (including Option E-Non-Tech) - the aggregate profile includes the effects of coincidence/non-coincidence of consumption patterns across the individual subcategories of customers adopting the different DER technologies/solutions and the relative weight that the number of customers adopting each DER technology/solution has included in the aggregate. These effects vary across the different consumer groups because of the underlying profiles used in the analysis but SCE only shows determinants for the TOU-GS-2 rate/consumer group here for illustration and reference and includes similar summaries in the workpapers being submitted in support of this analysis.

Table I-1
Illustrative Annual Energy Consumption by TOU Period for TOU-GS-2
Based on Average Profiles

Energy Consumption [kWh]										
Season	TOU Period	Aggregate			Option E		Paired	Standalone	EV	EV
		Non-DER	DER	Group TOTAL	NONTECH	NEM	Storage	Storage	Non-DCFC	DCFC
Summer	ON	12,460	9,159	11,249	6,618	10,701	13,308	24,875	4,897	11,039
Summer	MID	4,493	3,033	3,957	2,169	3,268	2,928	9,710	1,598	4,365
Summer	OFF	54,390	40,320	49,228	30,672	43,535	69,233	134,876	18,992	43,070
Winter	MID	25,793	19,620	23,529	13,295	23,600	25,451	53,776	12,461	26,786
Winter	OFF	41,632	30,263	37,462	21,846	46,231	70,016	103,016	12,876	21,542
Winter	S-OFF	44,936	36,037	41,672	27,407	23,528	36,296	106,578	22,930	55,371
Annual Totals		183,704	138,432	167,098	102,007	150,862	217,231	432,830	73,755	162,173

Table I-2
Illustrative Annual Coincident Demand by TOU Period for TOU-GS-2
Based on Average Profiles

Season	TOU Period	Aggregate			Option E		Paired	Standalone	EV	EV
		Non-DER	DER	Group TOTAL	NONTECH	NEM	Storage	Storage	Non-DCFC	DCFC
Summer	ON	147.12	107.91	132.71	85.84	131.95	209.23	305.98	55.37	127.34
Summer	MID	122.29	75.55	105.11	59.10	102.08	119.39	266.07	42.67	121.93
Summer	OFF	160.89	123.54	146.72	101.99	135.74	303.69	373.79	66.18	158.48
Winter	MID	224.21	170.34	203.40	126.58	216.46	316.00	472.47	110.80	234.25
Winter	OFF	174.61	148.15	163.46	110.21	217.82	436.32	433.22	83.16	189.53
Winter	S-OFF	240.14	194.06	220.60	155.26	215.23	462.36	587.65	138.06	316.51
Annual Totals		1,069.26	819.57	972.00	638.98	1,019.29	1,847.00	2,439.18	496.24	1,148.04

* Because SCE uses hourly profiles in this analysis the demand equivalent values diverge from SCE's 15 minute demand measure used for retail billing

Table I-3
Illustrative Annual Non-Coincident Demand by TOU Period for TOU-GS-2
Based on Average Profiles

Non Time-Dependent Demand [kW (h)]

Season	Month	Aggregate			Option E		Paired	Standalone	EV	EV
		Non-DER	DER	Group TOTAL	NONTECH	NEM	Storage	Storage	Non-DCFC	DCFC
Winter	January	25.0	21.4	22.9	16.4	28.6	57.2	59.0	13.6	26.2
Winter	February	29.2	22.1	26.6	18.8	28.5	55.6	76.7	15.8	31.2
Winter	March	30.3	22.1	27.3	19.0	26.3	50.3	71.8	16.1	34.6
Winter	April	35.1	26.5	31.8	22.5	26.9	50.8	93.0	17.0	39.7
Winter	May	31.3	24.2	28.5	20.3	24.9	47.6	75.9	17.2	36.6
Summer	June	37.1	26.7	33.2	23.0	26.9	37.1	82.6	16.1	37.3
Summer	July	38.1	26.7	33.6	22.9	27.7	57.1	80.3	15.3	39.3
Summer	August	42.8	33.5	39.3	27.1	35.9	87.9	100.4	16.6	40.4
Summer	September	42.9	36.7	40.6	28.9	50.7	121.6	110.4	18.2	41.5
Winter	October	35.3	29.0	32.6	23.2	32.6	74.7	87.0	19.4	47.9
Winter	November	27.8	23.3	25.8	17.5	28.3	56.8	62.9	19.7	49.6
Winter	December	26.2	25.5	25.1	17.5	32.7	72.7	61.3	19.3	50.7
Annual Totals		401.0	317.6	367.3	257.3	370.1	769.4	961.4	204.2	475.0

* Because SCE uses hourly profiles in this analysis the demand equivalent values diverge from SCE's 15 minute demand measure used for retail billing

Once billing determinants are summarized by each subcategory of customers, SCE then uses the disaggregated version of the three variants of rates (Default Option-D retail rate, MC Rates, and EPMC-Scaled MC rates) to calculate both the cost-to-serve and relative CTM for each grouping and subcategory of customers included in the analysis.

Table I-4 below illustrates the disaggregated rates for the TOU-GS-2 rate/consumer group that was then used to examine the individual cost contributions by customer subcategory. As can be seen in the table, non-marginal rate elements were included at the retail level when performing the bill calculations with the only differences across rates being retained in the cost-based variant of distribution and generation rates and the retail rate variant of distribution and generation rates.

Table I-4
Disaggregated Rates Used in DER Analysis

Charge Description	Non-Marginal Rate Components	Marginal Rate Components					
		GS-2 (TOU Rate Option -D)		GS-2 (EPMC Scaled Marginal Cost Rate)		GS-2 (Marginal Cost Rate)	
		Generation	Base Distribution	Generation	Base Distribution	Generation	Base Distribution
Energy Charges \$/kWh							
Non Time-Dependent Energy Charges							
Transmission	(\$0.00077)						
NSG, FRC etc.)	\$0.00775						
Public Purpose	\$0.02037						
Other (PUCRF, Bond)	\$0.00660						
Time-Dependent Energy Charges							
Summer On-Peak		\$0.14478	\$0.01306	\$0.12988		\$0.06604	
Summer Mid-peak		\$0.12146	\$0.01188	\$0.10896		\$0.05540	
Summer Off-Peak		\$0.10014	\$0.01161	\$0.10013		\$0.05091	
Winter Mid-peak		\$0.11535	\$0.01306	\$0.11534		\$0.05864	
Winter Off-Peak		\$0.11114	\$0.01188	\$0.11113		\$0.05650	
Winter Super-Off-Peak		\$0.06863	\$0.01121	\$0.06862		\$0.03489	
Time-Of-Use Demand Charges \$/kW-Month							
Summer On-Peak		\$11.96	\$10.17	\$11.96	\$8.14	\$6.08	\$4.89
Summer Mid-peak				\$0.37	\$1.92	\$0.19	\$1.15
Summer Off-Peak				\$0.59	\$9.15	\$0.30	\$5.50
Winter Mid-peak		\$4.73	\$2.65	\$2.41	\$0.80	\$4.73	\$0.48
Winter Off-Peak					\$0.35		\$0.21
Winter Super-Off-Peak					\$1.33		\$0.80
Non Time-Dependent Demand Charges \$/kW-Month	\$4.80		\$14.62		\$12.15		\$7.30
Customer Charges \$/Customer-Mon			\$140.00		\$228.80		\$137.49

Because the analysis uses rates that are disaggregated by each revenue and cost component, SCE computes a rather granular summary of cost-to-serve for each subcategory of customers used in the analysis across all rate/consumer groups. SCE evaluates the differences in cost-to-serve using EPMC-Scaled MC rates but examines relative CTM using both MC rates and EPMC-Scaled MC rates relative to the default rate Option-D. Table I-5 below illustrates the granular summary of cost-to-serve and customer bills based on the average profiles included in the TOU-GS-2 rate/consumer group – customer bills presented below for the TOU-GS-2 rate/consumer group show bills that are calculated for each average profile using the default rate Option-D, the Marginal Cost Rate, and the EPMC-Scaled Marginal Cost Rate. The summary bills are presented by both the cost category, and the subcategory of customers used in this analysis.

Table I-5
Illustrative Customer Bills and Cost to Serve

GS-2 (TOU Rate D) - DER Aggregate												
Month	Non-Marginal Components			Marginal Components						Total	\$/kWh	\$/kW(h)- Mo
	Trans	TOTCA	Delivery Other	Customer Charge	Distribution Grid	Distribution Peak	Generation/	Generation Peak	Generation Ramp			
							Energy					
January	102.9	(10.5)	346.9	140.0	313.3	167.4	947.4	0.0	87.0	2,097.3	0.20992	97.9
February	106.0	(9.8)	326.2	140.0	322.9	165.7	888.8	0.0	96.7	2,039.2	0.21705	92.3
March	106.2	(11.0)	368.7	140.0	323.5	178.3	1,001.4	0.0	93.3	2,203.3	0.20748	99.6
April	127.4	(10.9)	360.5	140.0	388.0	183.7	978.1	0.0	108.0	2,277.6	0.21938	85.8
May	115.9	(11.5)	381.0	140.0	353.1	187.0	1,031.9	0.0	101.3	2,301.8	0.20976	95.3
June	128.0	(12.7)	412.8	140.0	389.7	382.9	1,300.0	284.0	0.0	3,028.2	0.25471	113.6
July	128.1	(13.6)	431.3	140.0	390.2	388.7	1,353.3	283.7	0.0	3,105.7	0.25003	116.4
August	160.8	(14.7)	494.8	140.0	489.6	466.1	1,558.1	348.8	0.0	3,647.3	0.25590	108.9
September	176.2	(14.0)	484.3	140.0	536.6	483.6	1,520.5	373.8	0.0	3,704.2	0.26556	100.9
October	139.1	(12.1)	429.8	140.0	423.6	215.1	1,159.0	0.0	121.9	2,619.0	0.21155	90.4
November	111.8	(10.2)	375.3	140.0	340.5	182.7	1,020.0	0.0	97.1	2,259.0	0.20900	97.0
December	122.2	(10.5)	394.8	140.0	372.3	191.3	1,073.3	0.0	100.6	2,385.7	0.20978	93.7
Annual Total	1,524.5	(141.5)	4,806.4	1,680.0	4,643.4	3,192.4	13,831.9	1,290.2	805.9	31,668.2	0.22876	99.7

GS-2 (EPMC -Scaled Marginal Cost) - DER Aggregate												
Month	Non-Marginal Components			Marginal Components						Total	\$/kWh	\$/kW(h)- Mo
	Trans	TOTCA	Delivery Other	Customer Charge	Distribution Grid	Distribution Peak	Generation/	Generation Peak	Generation Ramp			
							Energy					
January	102.9	(10.5)	346.9	228.8	260.4	49.5	947.3	0.0	87.0	2,015.1	0.20169	94.0
February	106.0	(9.8)	326.2	228.8	268.3	52.2	888.7	0.0	96.7	1,959.8	0.20860	88.7
March	106.2	(11.0)	368.7	228.8	268.8	51.2	1,001.3	0.0	93.3	2,110.2	0.19871	95.4
April	127.4	(10.9)	360.5	228.8	322.4	59.4	977.9	0.0	108.0	2,176.4	0.20963	82.0
May	115.9	(11.5)	381.0	228.8	293.4	55.1	1,031.8	0.0	101.3	2,198.9	0.20038	91.0
June	128.0	(12.7)	412.8	228.8	323.9	470.0	1,260.0	306.0	0.0	3,120.3	0.26245	117.0
July	128.1	(13.6)	431.3	228.8	324.3	471.8	1,311.9	306.0	0.0	3,192.6	0.25702	119.6
August	160.8	(14.7)	494.8	228.8	406.9	580.2	1,510.5	375.5	0.0	3,746.6	0.26287	111.9
September	176.2	(14.0)	484.3	228.8	445.9	632.0	1,474.7	403.4	0.0	3,834.7	0.27491	104.5
October	139.1	(12.1)	429.8	228.8	352.0	66.1	1,158.9	0.0	121.9	2,487.0	0.20089	85.8
November	111.8	(10.2)	375.3	228.8	283.0	54.0	1,019.8	0.0	97.1	2,161.4	0.19998	92.8
December	122.2	(10.5)	394.8	228.8	309.4	58.2	1,073.1	0.0	100.6	2,278.4	0.20035	89.5
Annual Total	1,524.5	(141.5)	4,806.4	2,745.6	3,858.7	2,599.7	13,655.9	1,391.0	805.9	31,281.1	0.22597	98.5

GS-2 (Marginal Cost) - DER Aggregate													
Month	Non-Marginal Components			Marginal Components						Total	\$/kWh	\$/kW[h]- Mo	
	Trans	TOTCA	Delivery Other	Customer Charge	Distribution Grid	Distribution Peak	Generation/ Distribution		Generation Peak				Generation Ramp
							Energy						
January	102.9	(10.5)	346.9	137.5	156.5	29.7	481.7	0.0	44.3	1,291.6	0.12929	60.3	
February	106.0	(9.8)	326.2	137.5	161.3	31.4	451.8	0.0	49.2	1,256.1	0.13370	56.9	
March	106.2	(11.0)	368.7	137.5	161.6	30.8	509.1	0.0	47.5	1,353.1	0.12742	61.1	
April	127.4	(10.9)	360.5	137.5	193.8	35.7	497.2	0.0	54.9	1,398.9	0.13475	52.7	
May	115.9	(11.5)	381.0	137.5	176.3	33.1	524.6	0.0	51.5	1,411.5	0.12863	58.4	
June	128.0	(12.7)	412.8	137.5	194.6	282.4	640.6	155.6	0.0	1,942.4	0.16338	72.9	
July	128.1	(13.6)	431.3	137.5	194.9	283.5	667.0	155.6	0.0	1,988.3	0.16007	74.5	
August	160.8	(14.7)	494.8	137.5	244.5	348.7	768.0	190.9	0.0	2,334.2	0.16378	69.7	
September	176.2	(14.0)	484.3	137.5	268.0	379.8	749.8	205.1	0.0	2,389.9	0.17134	65.1	
October	139.1	(12.1)	429.8	137.5	211.5	39.7	589.2	0.0	62.0	1,599.3	0.12918	55.2	
November	111.8	(10.2)	375.3	137.5	170.0	32.5	518.5	0.0	49.4	1,386.6	0.12829	59.5	
December	122.2	(10.5)	394.8	137.5	185.9	35.0	545.6	0.0	51.1	1,463.5	0.12869	57.5	
Annual Total	1,524.5	(141.5)	4,806.4	1,649.9	2,318.8	1,562.2	6,943.2	707.2	409.8	19,815.4	0.14314	62.4	

Table I-6 below summarizes CTM estimates across customer subcategories and CTM values are shown for both the EPMC-Scaled Marginal Cost rate and the Marginal Cost Rate relative to the default rate Option-D.

Table I-6
Contribution to Margin

Customer Subcategory	CTM MC Rates		CTM EPMC Scaled MC Rates	
	\$/kWh	\$/kW(h)-Month	\$/kWh	\$/kW(h)-Month
Non-DER	61.3%	61.3%	2.1%	2.1%
Aggrgeate DER	59.8%	59.8%	1.2%	1.2%
Rate Group Total	60.8%	60.8%	1.8%	1.8%
Option E NONTECH	57.5%	57.5%	-0.2%	-0.2%
NEM	61.2%	61.2%	1.7%	1.7%
Paired Storage	59.0%	59.0%	1.2%	1.2%
Standalone Storage	62.9%	62.9%	3.6%	3.6%
EV Non-DCFC	55.8%	55.8%	-1.2%	-1.2%
EV DCFC	59.3%	59.3%	1.7%	1.7%

Findings

The TOU-GS-2 rate/consumer group has the highest penetration of DER adopters in comparison to the other rate groups analyzed in this Study. Table I-7 below summarizes the relative adoption of DERs across all rate/consumer groups for the recorded year 2022 and the forecast year 2025. Data values shown as omitted in the table to remain in compliance with SCE's 15/15 Rule. In rate groups where DER adoption remains relatively low, the inferential value of the Cost-to-Serve or Contribution-to-Margin may be less reliable. For this reason, in this section SCE will review findings pertinent to the TOU-GS-2 rate/consumer group and present inference based on data and computations for that group. The TOU-8-SEC rate/consumer group that represents large power customers appears to be the next most mature rate group in terms of DER adoption. While in general the large power rate groups (TOU-8) have fewer DER adopters, larger customer size makes this group critical in examining the effects of DER adoption because customers who adopt DERs and induce flexibility in their demand of electricity from the grid, can experience sizeable changes in bills, which when complemented with the appropriate rate structure can have a material impact on cost avoided by the grid.

Table I-7
Number of Accounts (2022) And Forecasted (2025)

Rate Group	Option E (NONTech)	NEM ONLY	Paired Storage	Standalone Storage	EV Rate NONDCFC	EV Rate DCFC	Non-DER	DER
TOU-GS-2 Recorded 2022	26,442	2,969	114	71	287	155	58,165	30,038
TOU-GS-2 Forecast 2025	26,442	4,888	276	199	414	224	55,956	32,443
TOU-GS-3 Recorded 2022	1,308	694	66	103	-	-	4,914	2,171
TOU-GS-3 Forecast 2025	1,308	1,143	79	113	-	-	4,442	2,643
TOU-PA-2 Recorded 2022	7,707	144	Omitted	Omitted	-	-	13,700	7,862
TOU-PA-2 Forecast 2025	7,707	237	42	40	-	-	13,536	8,026
TOU-PA-3 Recorded 2022	580	55	-	Omitted	-	-	950	642
TOU-PA-3 Forecast 2025	580	91	Omitted	Omitted	-	-	909	683
TOU-8-SUB Non-standby Recorded 2022	Omitted	17	-	Omitted	-	-	109	29
TOU-8-SUB Non-standby Forecast 2025	Omitted	28	Omitted	Omitted	Omitted	Omitted	94	48
TOU-8-PRI Non-standby Recorded 2022	16	116	Omitted	39	Omitted	-	518	182
TOU-8-PRI Non-standby Forecast 2025	16	191	Omitted	40	Omitted	Omitted	441	267
TOU-8-SEC Non-standby Recorded 2022	22	206	28	81	17	129	1,741	483
TOU-8-SEC Non-standby Forecast 2025	22	339	32	84	37	282	1,601	796

*Omitted accounts do not meet the 15/15 rule.

Table I-8 below summarizes SCE’s annual cost-to-serve across different customer cost categories examined in this Study. SCE performed this disaggregated analysis across all DER types and summarizes results in the table below, that show SCE’s estimate of cost-to-serve based on EPMC-Scaled Marginal Cost rates by month and customer subcategory.

Table I-8
Cost to Serve By Customer Category (EPMC Scaled Marginal Costs)

SCE Cost-To-Serve - \$/kWh [EPMC-Scaled Marginal Cost]

Season	Month	Aggrgeate			Option E		Paired Storage	Standalone Storage	EV Non-DCFC	EV DCFC
		Non-DER	DER	Group TOTAL	NONTECH	NEM				
Winter	January	0.18975	0.20169	0.19204	0.12670	0.20784	0.22098	0.18015	0.24000	0.22290
Winter	February	0.20155	0.20860	0.20366	0.14684	0.22109	0.23364	0.19537	0.24643	0.23085
Winter	March	0.19528	0.19871	0.19631	0.15003	0.21260	0.22580	0.18447	0.22694	0.21407
Winter	April	0.20394	0.20963	0.20551	0.16871	0.22072	0.23674	0.19932	0.22712	0.21972
Winter	May	0.19404	0.20038	0.19568	0.15990	0.21139	0.22244	0.18438	0.22563	0.20891
Summer	June	0.25974	0.26245	0.26034	0.21351	0.26719	0.27881	0.24073	0.29477	0.28592
Summer	July	0.25443	0.25702	0.25474	0.20392	0.26267	0.30131	0.23481	0.28884	0.27872
Summer	August	0.25595	0.26287	0.25796	0.17930	0.25993	0.27925	0.24165	0.28879	0.27363
Summer	September	0.26287	0.27491	0.26648	0.17766	0.29043	0.32114	0.25420	0.29966	0.27099
Winter	October	0.19637	0.20089	0.19715	0.13776	0.20808	0.21951	0.18802	0.22410	0.20232
Winter	November	0.19554	0.19998	0.19628	0.13702	0.21447	0.22751	0.18312	0.22759	0.20431
Winter	December	0.19159	0.20035	0.19318	0.12674	0.21281	0.23331	0.18070	0.22511	0.19843
Annual Average		0.22015	0.22597	0.22151	0.23897	0.23522	0.25456	0.20894	0.25144	0.23414

SCE Cost-To-Serve - \$/kW(h)-Month [EPMC-Scaled Marginal Cost]

Season	Month	Aggrgeate			Option E		Paired Storage	Standalone Storage	EV Non-DCFC	EV DCFC
		Non-DER	DER	Group TOTAL	NONTECH	NEM				
Winter	January	103.3	94.0	103.2	95.4	90.0	67.5	95.8	83.8	73.2
Winter	February	87.6	88.7	87.9	83.4	82.9	64.0	76.0	75.8	64.1
Winter	March	92.1	95.4	93.1	88.5	90.8	67.6	87.3	84.2	69.0
Winter	April	82.1	82.0	82.2	77.4	84.5	63.4	71.8	81.2	63.9
Winter	May	92.6	91.0	92.4	86.0	92.6	67.7	86.4	82.6	69.3
Summer	June	115.5	117.0	116.2	110.6	118.5	101.6	113.3	112.5	99.7
Summer	July	117.7	119.6	119.0	113.1	120.7	78.6	118.1	116.2	100.2
Summer	August	114.1	111.9	113.5	108.1	118.3	91.0	109.9	114.7	104.8
Summer	September	111.1	104.5	109.1	101.4	94.7	75.0	102.5	108.6	103.6
Winter	October	87.7	85.8	87.9	81.0	87.0	62.5	80.1	78.8	70.3
Winter	November	93.6	92.8	94.3	90.2	87.1	65.9	89.3	76.8	68.1
Winter	December	99.9	89.5	98.6	91.8	82.5	58.4	92.3	79.2	71.0
Annual Average		100.8	98.5	100.8	94.8	95.9	71.9	94.1	90.7	79.8

* Because SCE uses hourly profiles in this analysis the demand equivalent values diverge from SCE's 15 minute demand measure used for retail billing

SCE shows cost-to-serve in both dollars-per-kWh and dollars-per-kW. Doing so presents cost-to-serve that normalizes for differences in energy consumption (kWh) or max customer demand (kW) that may exist between the different customer subcategories who adopt DER solutions as well as for customers who are non-adopters. This becomes important for two reasons: (1) The propensity for customers to adopt specific DER solutions can vary based on both the intra-class composition of customer end-uses as well as inter-class parity of the structural design of prices/rates and how they complement with the underlying consumption needs of the customer prior to adopting a specific DER solution; and (2) Different DER solutions can induce varying degrees of flexibility in customer consumption patterns that can result in divergence between the amount of energy (kWh) consumed by the customer, and the amount of capacity (kW-demand) a customer requires from the grid. SCE views the grid, not as a homogenous resource, but a mosaic of capacity and energy resources that when optimized, ensure supply is available, on-demand, for a

customer, and more importantly, ensuring that the capacity needed is ubiquitously available in a safe, reliable, and resilient manner. SCE's cost-to-serve rates include a blend of energy (kWh) and demand (kW) price elements that when applied to average hourly customer profiles, or to group specific billing determinants, help examine directional or relative comparison of the impact customer behavior can exact on the grid. It is important to note here that SCE's use of average hourly profiles causes the measure of demand used in this analysis to be the maximum *hourly* demand of the average profile and diverges somewhat from the *fifteen-minute interval* measure of demand that SCE uses for billing - average hourly profiles aggregate usage patterns across individual customers included in the group being analyzed, and the process of averaging dilutes the diversity of demand each customer in the group can exact on the grid.

In analyzing cost-to-serve under the Rates Analysis methodology described here, SCE observes that the blend of cost parameters between energy, coincident demand, non-coincident demand, and customer access and engagement have an impact on a customer's annual cost-to-serve and varies based on how the load profile affects each parameter. In the TOU-GS-2 rate/consumer group illustrated here, cost-to-serve can vary by season or month and can have varying interpretation when those annual costs in dollars-per-year are normalized for a customer's annual energy consumption in kWh-per-year or a customer's annual capacity needs expressed as the sum of the maximum monthly demand (kW) determinants in the year. Both are credible approaches to interpreting SCE's estimates of cost-to-serve and present pertinent insight in viewing the interaction of a customer's load profile on the different cost parameters included in the EPMC-Scaled Marginal Cost Rate – the process of normalizing for demand helps infer costs relative to a customer's demand needs while normalizing for energy consumption helps infer costs relative to the volume of energy consumed. The interplay between a customer's coincident (CP-kW) and/or non-coincident demand (NCP-kW) with a customer's energy throughput (kWh), as calculated by the customer's load factor also affects the estimated cost-to-serve – generally, higher load factors can result in lower cost-to-serve estimates when normalized for energy consumed because, all things equal, a higher energy throughput for a given level of demand (kW) reduces the cost of an incremental kWh of energy consumed from the grid. Customer groupings and sample/ population size can also have a noticeable impact on average profiles, and in turn, better confidence in the cost-to-serve estimates – a lower volume of adopters for a certain DER

solution/technology can result in reduced confidence of the estimated cost-to-serve for that subgroup, In Table I-9 below, SCE presents a summary of cost-to-serve across the different customer subcategories for the TOU-GS-2 rate/consumer group and presents a graphical illustration of the relationship between cost-to-serve and annual load factor in Figure I-3. In Table I-9 below, the [\$/kW(h)-Month] variant of presenting cost-to-serve is derived by dividing the annual calculated cost using EPMC Marginal Cost rates by the sum of the maximum demand (hourly in this case as SCE uses average hourly profiles) for each month of the year. These [\$/kW(h)-Month] values can be converted to annualized values ([\$/kW(h)-Year] by multiplying by twelve. These values will be lower when SCE calculates cost-to-serve using unscaled Marginal Cost Rates and are different from the \$/kW-Year presented in the MCRR methodology. Some results presented in table I-9 appear counterintuitive when high demand-low load factor subcategories like DCFC show lower cost-to-serve than Non-DCFC, but that could be driven by the underlying load profiles used to calculate the cost-to-serve for each customer group. There may also be some intuition around Paired Storage showing lower cost-to-serve than Standalone Storage, but the magnitude of the difference may be more driven by the differences in the underlying load profiles in the analysis – storage and EV profiles for some groups are based on the limited size of adopters in the base year 2022 that was also used to project profiles for the year 2025.

Table I-9
Cost-to-Serve Summary (TOU-GS-2)

Customer Subcategory	Cents/kWh	\$/kW(h)-Month
Non-DER	\$22.0	\$100.8
Aggrgeate DER	\$22.6	\$98.5
Rate Group Total	\$22.15	\$100.77
Option E NONTECH	\$23.90	\$94.76
NEM	\$23.52	\$95.89
Paired Storage	\$25.46	\$71.87
Standalone Storage	\$20.89	\$94.06
EV Non-DCFC	\$25.14	\$90.72
EV DCFC	\$23.41	\$79.81

Figure I-3
Cost-to-Serve vs. Load Factor

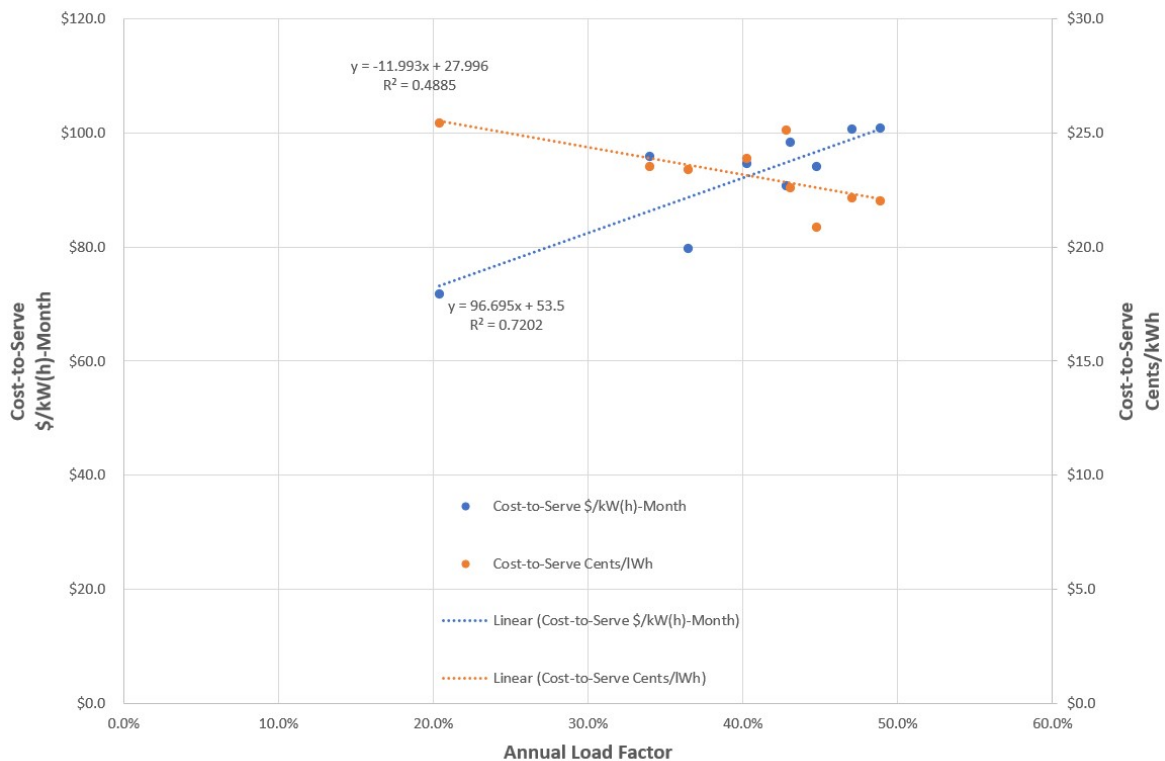
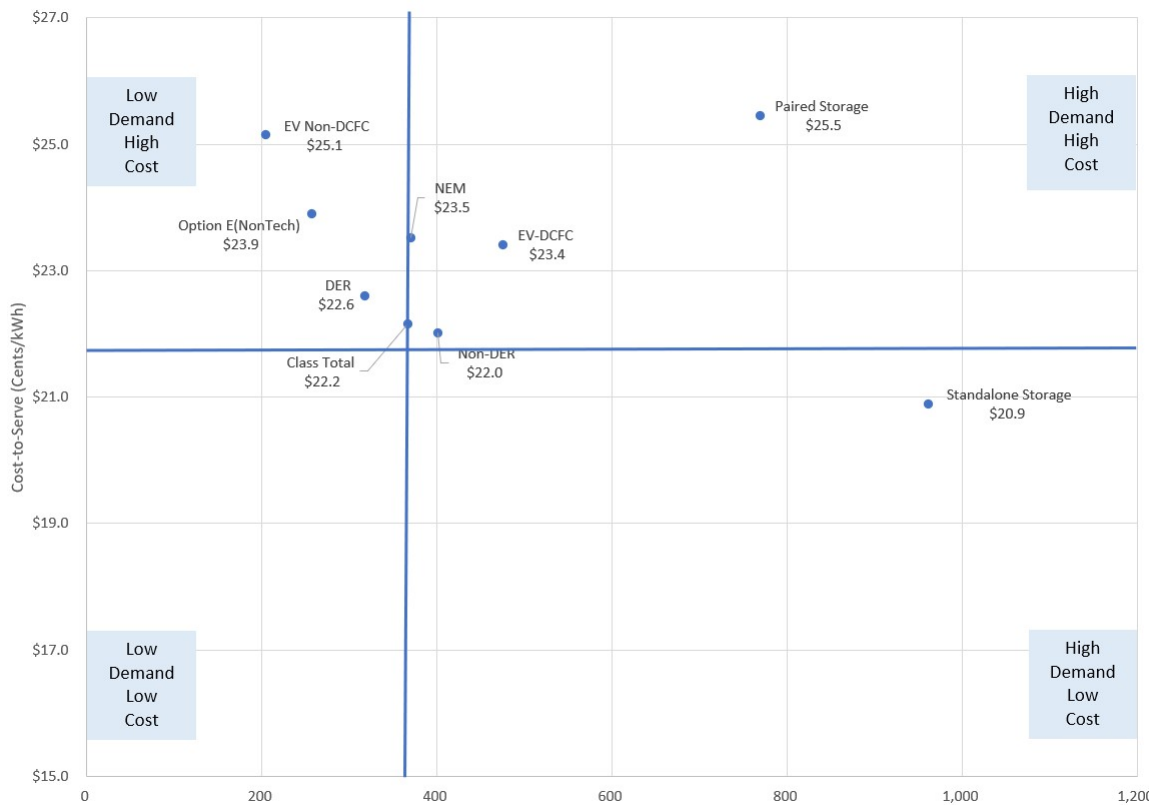


Figure I-4 illustrates cost-to-serve normalized for demand [\$/kW(h)-Month] and the respective sums of the maximum monthly demands of the average load profiles that are used in the analysis – SCE presents the data by cost quadrant where the quadrants as presented in the figure are defined by the intersection of the data point defined as the rate/consumer group total cost-to-serve. The graph also labels each customer subcategory and the relative dispersion of costs across all quadrants.

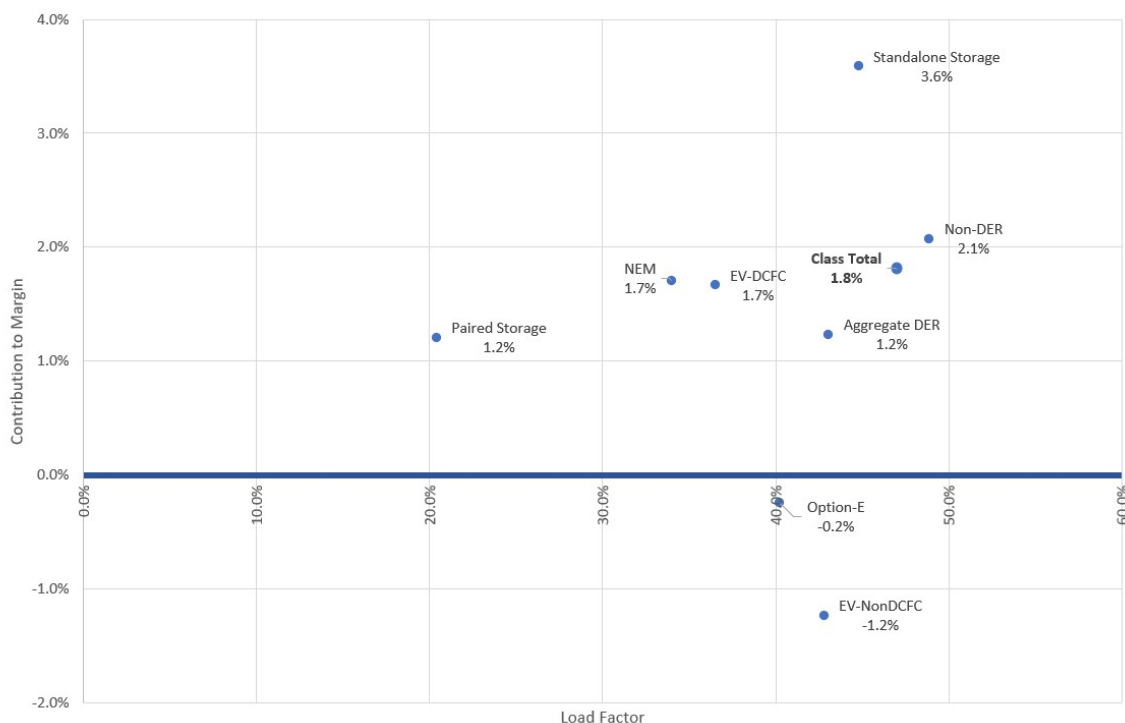
Figure I-4
Cost-to-Serve (cents/kWh vs. Annual Sum of Monthly Max kW) Average Profiles



As illustrated in Table I-6, which shows the relative CTM for each customer category, SCE calculated contribution to margin based on EPMC-Scaled Marginal Cost rates as well as unscaled Marginal Cost Rates. Both marginal cost rates are identical in structural design and only differ in the level at which each rate is set, in that the EPMC-scaled marginal cost rates are set by applying each functional revenue component’s

EPMC scalar to the unscaled marginal cost rate to ensure revenue neutrality to SCE’s authorized revenues as included when setting SCE’s retail rates, which in this case is rate Option-D. In Figure I-5, SCE presents a graphical illustration of the relationship between contribution to margin and load factor for each subcategory of customers analyzed in this Study. Albeit nominal when using EPMC marginal cost rates, all customer subcategories show positive CTM relative to the default rate Option-D with Option-E and EV-Non-DCFC customers – because SCE uses average profiles when calculating CTMs in this analysis, the results shown in Figure I-5 could be influenced by the confidence of the estimate in the average profile for categories with relatively low adoption rates, and the extent to which forward estimates in the average profiles dilute customer diversity when computing CTM using actual recorded billing determinants.

Figure I-5
CTM % EPMC-Scaled Marginal Cost Rate



SCE also uses another tool to analyze how customer subgroups can cluster relative to the class: the relationship between a customer subgroup’s load factor and class-coincidence factor. Figure I-6 below

shows this relationship for the various subgroup of customers analyzed in the TOU-GS-2 rate/consumer group. Because SCE uses average profiles in this analysis, the results may not provide as robust an inference when compared to the same analysis done on an individual customer basis. However, the figure below illustrates the relationship between class-coincidence factor and load factor based on the average profiles used in this analysis for each customer subcategory in the TOU-GS-2 rate/consumer group. As can be seen in Figure I-6, storage adopters, mobile or otherwise, and NEM induce flexibility in consumption behavior that presents noticeable divergence in load factors and class coincidence when compared to results computed for the rate/consumer group.

Figure I-6
Monthly Class Coincidence v/s Monthly Load Factor by Subcategory



SCE also evaluated SCE's estimates of cost-to-serve for the current DER and non-DER customers using their individual billing determinants as calculated on their 2022 metered data. These billing determinants do not account for forecasted levels of technology adoption or any potential changes in the customer profiles resulting from increased adoption. As the diversity in the average profile produces a lower cost-to-serve as compared to the cost-to-serve for the average individual billing determinants. While the DER customers within the TOU-GS-2 rate class are slightly more expensive to serve than the non-DER customers (\$0.302/kWh versus \$0.247/kWh respectively), there is considerable relative variation within the DER technology types. Most notably, the electric vehicle segments, both non-DCFC and DCFC, are significantly more costly when compared to a non-adopter.

Cost-To-Serve: Marginal Cost Revenue Responsibility (MCRR)

Purpose

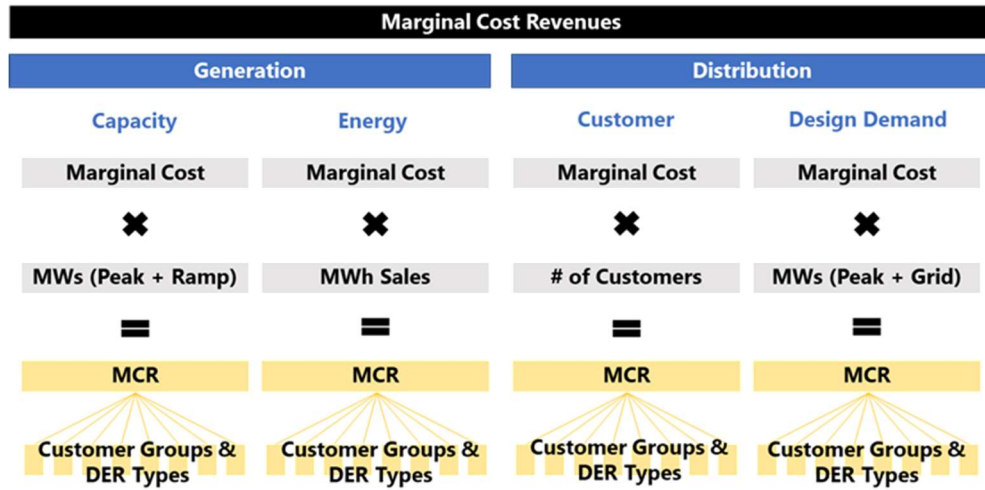
This section describes SCE's DER cost-to-serve analysis that hinges to the same methods and calculations that SCE uses in Exhibit SCE-03, and then derives marginal cost rates by customer subcategory further examined in this Study. At a high level, marginal cost revenue responsibility (MCRR) for each consumer group is calculated by multiplying the unit marginal costs with the identified drivers of cost for each cost component. In this analysis SCE then derives marginal cost rates taking the customer subcategory specific MCRR and dividing by the respective rate recovery billing determinants used for setting retail rates. This analysis can be viewed as a bottoms-up, granular assessment of cost-to-serve that considers the unique disposition of customer usage behavior and the corresponding effect that behavior can have on the drivers of cost. As DER adoption across SCE's consumer groups continues to evolve and mature, SCE sees value in continuing this analysis in subsequent cycles as an important tool that helps inform the design of rates, as well as the merits of class categorization for certain DER solutions in the future. Much like computing on the edge of the prosumer, consumer, and platform interface will fundamentally change how users experience content, the onset and continued commercialization of customer-sited storage technologies, mobile or otherwise, will present a unique opportunity that has the potential to fundamentally change how customers

interact with the grid and, if integrated appropriately, enhance how customers can meaningfully contribute to an optimized grid, and in the long-run, reduce overall system costs.

Methodology

While SCE uses the same general methods described in Exhibit SCE-03 when developing MCRR, in this Study, SCE determines MCRR for each customer subcategory by applying unit marginal costs to the drivers of cost for each specified customer subcategory examined in this analysis. As described in the Load Analysis section of this Appendix, customer subcategories identified for examination are broadly categorized into two main categories, non-DER and DER customers, with subsequent DER subcategories being Option-E (NONTech), NEM ONLY, Paired Storage, Standalone Storage, EV Rate (NONDCFC), and EV Rate (DCFC). EV subcategories are defined by customers subscribing to SCE's commercial EV rate schedules namely TOU-EV-8 and TOU-EV-9 and further subcategorized as DCFC and NONDCFC. These same revenues are then divided by recorded billing determinants. Please see Figure I-7 below for an illustration of this process. Figure 3 is a schematic illustration that shows the steps SCE uses when developing marginal cost revenue responsibility for each subcategory of customers used in the analysis. SCE retains the same functional disposition of cost, namely Generation and Distribution, and develops revenue responsibility for each category of cost described in Exhibit SCE-02. By doing so, SCE retains line-of-sight comparison of revenue responsibility computed in this analysis with those computed for each consumer group in Exhibit SCE-03.

Figure I-7
Illustration of Marginal Cost Rates Derivation



SCE presents a brief description of specific inputs and assumptions used in this study to calculate marginal cost revenue responsibility and in turn derive marginal cost rates.

- **Marginal Costs:** SCE uses the same unit marginal costs developed for this Application and described in Exhibit SCE-02.
 - Generation Capacity Marginal Cost is defined by the Net Cost of New Entry (NetCONE) for a one-megawatt (1 MW) solar generator paired with a one- megawatt, six-hour duration (6 MWh) battery that is postulated to provide capacity during system peak and ramp constraints.
 - Generation Energy Marginal Costs are for the forecast year 2025 and are derived using a fundamental cost optimization PLEXOS model.
 - Design Demand Marginal Costs reflect the real economic carrying cost of adding new capacity on SCE’s distribution grid with such cost identified for each asset layer of the distribution system namely, Distribution Substations (A-Banks), Distribution Circuits, Subtransmission Substations (A-Banks), and Subtransmission Circuits. SCE further

functionalizes these costs into grid and peak and retains the same composition of the grid versus peak split for this analysis.

- **Drivers of Cost:** SCE uses the same methods to derive the drivers of cost as described in exhibit SCE-03 but develops cost drivers for each subcategory of customers examined in this Study. In doing so SCE had to make certain assumptions of customer subcategory contribution to cost that are further described below.
 - Generation Capacity: As described in Exhibit SCE-03, the driver of cost for Generation Capacity is based on SCE's Net Load and identified by the megawatt contributions of rate/consumer groups. For Generation Grid Peak constraints, SCE uses the top one-hundred hours of the bundled net load and for Generation Grid Ramp constraints, SCE uses the top ten maximum daily ramp events of the bundled net load. Ramp is defined as the maximum daily three- hour *positive* change in Bundled Net Load. For Generation costs, SCE derives estimates of rate/consumer cost contributions using Bundled Service Load. To derive cost contributions for each subcategory of customers examined in this analysis, SCE uses the customer subcategory load shapes and the rate/consumer group specific load shapes specifically developed for this Study. SCE then determined the pro-rata share (expressed as a percentage) for each customer subcategory to the overall rate/consumer group megawatt in each constraint hour. SCE then averaged the percentage share across all pertinent hours to derive the customer subcategory contributions to each system constraint – top one hundred, for peak, and top ten daily max, for ramp. SCE had to make additional adjustments to these customer subcategory contributions to ensure parity with the assumptions around the reasonableness of DER penetration expected in each rate/consumer group for the forecast year. These adjustments ensured that megawatt contributions aligned with the underlying billing determinants that were then used to determine customer subcategory specific marginal cost rates.

- Generation Energy: As described in Exhibit SCE-03, the driver of cost for Generation Energy is based on SCE's forecast of customer energy consumption (kWh) in 2025 for each rate/consumer group. In this analysis, the GWh consumption by each customer subcategory used in the recorded year 2022 is the basis for forecasting DER penetration and the corresponding estimate of GWh consumption by customer subcategory for the forecast year 2025. The Load Analysis section of this Appendix contains additional details on SCE's methods in estimating load profiles and GWh consumption for the forecast year 2025 – to account for any differences driven by the underlying assumptions used in this analysis, GWh estimates for each customer subcategory were normalized to SCE's estimate of GWh such that the total GWh for each rate/consumer group as a sum of each customer subcategory equaled the estimate of rate/consumer GWh used in the MCRR model.
- Design Demand - Distribution Peak Capacity: As described in SCE-03, the driver of cost for Design Demand Distribution Peak Capacity costs is based on SCE's estimate of Peak Load Risk Factors (PLRF) for each asset category on the distribution system. Peak Load Risk Factors, expressed as a percentage in each hour, are derived using a deterministic approach that models asset specific peak load durations – SCE applies load/planning thresholds relative to asset specific capacity limits measured against asset specific hourly loads. SCE determines rate/consumer group contributions to these PLRF hours by using rate/consumer group aggregate load profiles and multiplying the megawatt contribution in each PLRF hour with the PLRF percentage in that respective hour. In determining customer subcategory specific contribution to PLRF hours, SCE uses the same approach as described for Generation Capacity where SCE determines the pro-rata share (expressed as a percentage) for each technology type or customer subcategory in each PLRF hour. SCE then averages these percentages across all pertinent PLRF hours to derive the customer subcategory specific contribution as a percentage share of the total rate/consumer group specific megawatt contribution for each asset category - A-Banks, B-Banks and Distribution Circuits. For all Distribution Function cost determinations SCE uses Retail Service Load where Retail

Service is defined as the aggregate of all customer load namely Bundled Service, Direct Access Service, and Community Choice Aggregation Service. Because the underlying assumptions used to derive the megawatt contributions by customer category in this analysis can vary from the aggregate rate/consumer group contributions used in SCE's MCRR model in this Application, SCE normalized the customer subcategory megawatt contributions to the rate/consumer group PLRF-Megawatt contributions used in the MCRR model. Doing so maintains line-of-sight comparison between rate/consumer group contributions used in the MCRR model and the disaggregated customer subcategory contributions developed in this analysis.

- *Design Demand – Distribution Grid Capacity:* As described in Exhibit SCE-03, the driver of cost for Design Demand Distribution Grid Capacity cost is based on Effective Demand Factors (EDF) that SCE models by rate/consumer group as applied to the annual noncoincident peak (NCP) megawatts for each rate/consumer group – EDFs are presented as a ratio and derived using a stochastic process. EDFs reflect the expected change in the modeled peak load of a rate/consumer specific circuit by a unit change (add or subtract) of a representative customer on that modeled circuit. For the purposes of this Study, SCE did not develop customer subcategory specific EDFs but used the rate/consumer group EDFs that were developed for this Application. SCE used the recorded year 2022 NCP data for each customer subcategory that were then adjusted to represent 2025 data by applying a sampling weight which represents a ratio of forecasted 2025 DER accounts and 2022 DER accounts. Revenues are developed for both the subtransmission and distribution systems. Noncoincident kilowatts are not normalized to the MCRR level due to possible timing difference each DER type may have to the class total.
- **Recorded Billing Determinants:** Billing determinants are derived using the 2022 interval load data. For rate groups with a substantial number of accounts (such as TOU-GS-2 and TOU-PA-2), a representative sample of accounts is selected. For other rate groups with a lower number of service accounts, billing determinants are derived using the entire population. SCE then determines sample

weights for each customer subcategory in the year 2022. To estimate the billing determinants for 2025, the sampling weights are adjusted based on the ratio of the forecasted number of DER accounts in 2025 to the recorded counts for each DER category within a rate group in 2022. Take TOU-8-SEC Non-standby as an example, there were 129 EV DCFC accounts recorded in 2022, and the projected EV DCFC count for 2025 is 282 accounts, so the adjustment ratio is 2.2 (282 divided by 129). This means that one EV DCFC account on TOU-8-SEC Non-standby in 2022 would represent 2.2 accounts in 2025. Once billing determinants by each subcategory and the corresponding sum in aggregate are determined for the year 2025, they are further normalized to aggregate value of billing determinants of the rate/consumer group used for rate setting and in the MCRR model. Doing so retains line-of-sight between rate/consumer group MCRR determinants and the determinants used in this Study.

- **Marginal Cost Rates:** Marginal cost rates are calculated by dividing MCRR by the respective cost recovery billing determinants. For Capacity, SCE uses time-related demand (TRD-kW) determinants and non-coincident demand (FRD-kW) determinants.
 - **Generation Capacity Marginal Cost Rates:** SCE uses **Bundled Service** TRD-KW normalized to level of bundled sales in the forecast year 2025.
 - **Generation Energy Marginal Cost Rates:** SCE uses **Bundled Service** GWhs normalized to the level of bundled sales GWh in the forecast year 2025.
 - **Design Demand Distribution Peak Marginal Cost Rates:** SCE uses **Retail Service** TRD-kW normalized to the retail sales levels in the forecast year 2025.
 - **Design Demand Distribution Grid Marginal Cost Rates:** SCE uses **Retail Service** FRD-kW normalized to the retail sales level of the forecast year 2025.

Findings

This study assisted in better shaping SCE's understanding of specific DER technology types' cost-to-serve. As stated in the above section, marginal cost rates are derived by dividing the marginal cost revenues and the cost recovery billing determinants. The interplay between these two components can affect the inference of the results. The results from this study should be interpreted with caution due to the

assumptions made when deriving the marginal cost revenues and cost recovery billing determinants. Tables I-10 through I-15 are excerpts from the accompanying workpaper that conveys the study's findings for the TOU-8-Secondary rate group. Table I-16 is an excerpt from the accompanying workpaper that summarizes the study's findings for the TOU-GS-2 rate group.

Table I-10
TOU-8-Secondary Generation Capacity (Peak) Marginal Cost by DER Type

TOU-8-SEC Marginal Cost Rates Generation Peak Capacity	Summer (\$/KW - Month)			Winter (\$/KW - Month)			Annualized \$/kW-Yr	% of Aggregate DER With Option E	% of NON DER
	On	Mid	Off	Mid	Off	Super-Off			
TOU-8-SEC Rate/Consumer Group Total	\$7.1	\$0.2	\$0.4	-	-	-	\$30.6		
NON DER	\$6.9	\$0.2	\$0.4	-	-	-	\$29.7		←
Aggregate DER with Option E	\$7.6	\$0.2	\$0.5	-	-	-	\$33.0	←	
Aggregate DER without Option E	\$7.9	\$0.2	\$0.5	-	-	-	\$34.3		
Option E (NONTech)	\$4.0	\$0.1	\$0.2	-	-	-	\$17.3	52%	58%
NEM Only	\$8.5	\$0.2	\$0.5	-	-	-	\$36.6	111%	123%
Paired Storage	\$5.8	\$0.1	\$0.3	-	-	-	\$25.1	76%	84%
Standalone Storage	\$5.7	\$0.1	\$0.3	-	-	-	\$24.4	74%	82%
EV- NONDCFC	\$3.9	\$0.1	\$0.2	-	-	-	\$16.8	51%	57%
EV- DCFC	\$9.7	\$0.2	\$0.6	-	-	-	\$41.8	126%	140%

Table I-10 contains the Generation Capacity Peak marginal cost rates for the various DER technology types. As seen in Table I-8 above, EV-NONDCFC and EV-DCFC have the largest variance when compared to the customer category noted as NON DER – customers who have not adopted a DER solution. In looking at the annualized basis of cost, EV-NONDCFC's Generation Peak Capacity cost is estimated at approximately **57 percent** of the NON DER category, while EV-DCFC 's Generation Peak Capacity cost is approximately **140 percent** of the NON DER category. NEM also shows a higher cost and is estimated at approximately **123 percent** of the NON DER category.

Table I-11
TOU-8-Secondary Generation Capacity (Ramp) Marginal Cost by DER Type

TOU-8-SEC Marginal Cost Rates Generation Ramp Capacity	Summer (\$/KW - Month)			Winter (\$/KW - Month)			Annualized \$/kW-Yr	% of Aggregate DER With Option E	% of NON DER
	On	Mid	Off	Mid	Off	Super-Off			
TOU-8-SEC Rate/Consumer Group Total	-	-	-	\$3.5	-	-	\$27.7		
NON DER	-	-	-	\$3.3	-	-	\$26.1		←
Aggregate DER with Option E	-	-	-	\$4.0	-	-	\$32.0	←	
Aggregate DER without Option E	-	-	-	\$4.1	-	-	\$32.9		
Option E (NONTech)	-	-	-	\$2.3	-	-	\$18.3	57%	70%
NEM Only	-	-	-	\$4.4	-	-	\$35.4	107%	136%
Paired Storage	-	-	-	\$3.1	-	-	\$24.4	74%	93%
Standalone Storage	-	-	-	\$1.9	-	-	\$15.5	47%	59%
EV- NONDCFC	-	-	-	\$1.4	-	-	\$11.5	35%	44%
EV- DCFC	-	-	-	\$6.0	-	-	\$47.8	145%	183%

Table I-11 contains the Generation Capacity Ramp marginal cost rates for the various DER technology types. Generation Flex Capacity (ramp) marginal cost follows a similar pattern to the Generation Capacity Peak marginal cost where EV-NONDCFC and EV-DCFC have the largest variance when compared to the NON DER category. On an annualized basis, EV-NONDCFC's Generation Flex Capacity cost is approximately **44 percent** of the NON DER category, while EV-DCFC's Generation Flex Capacity cost is significantly higher at approximately **183 percent** of the NON DER category. NEM also shows a higher cost and is estimated at approximately **136 percent** of the NON DER category.

The summary tables for both Peak and Ramp Generation Capacity prompt inference that there appears to be a sizeable degree of divergence in Generation Capacity costs for the EV subcategory of customers where EV-NONDCFC appears to be *lower* cost-to-serve relative to a customer considered NON DER (a non-adopter) whereas the EV-DCFC subcategory of customers can have a noticeably *higher* cost-to-serve compared to the NON DER category *and* the EV-NONDCFC category.

Table I-12
TOU-8-Secondary Generation Energy Marginal Cost by DER Type

TOU-8-SEC Marginal Cost Rates Generation Energy	Summer (\$/KWh)			Winter (\$/KWh)			Annualized \$/kWh	% of Aggregate DER With Option E	% of NON DER
	On	Mid	Off	Mid	Off	Super-Off			
TOU-8-SEC Rate/Consumer Group Total	0.06605	0.05541	0.05092	0.05865	0.05651	0.03489	0.05067		
NON DER	0.06720	0.05134	0.05254	0.05683	0.05658	0.03419	0.05055		←
Aggregate DER with Option E	0.06720	0.05134	0.05254	0.05683	0.05658	0.03419	0.05133	←	
Aggregate DER without Option E	0.06720	0.05134	0.05254	0.05683	0.05658	0.03419	0.05135		
Option E (NONTECH)	0.06720	0.05134	0.05254	0.05683	0.05658	0.03419	0.05118	100%	101%
NEM Only	0.06720	0.05134	0.05254	0.05683	0.05658	0.03419	0.05212	102%	103%
Paired Storage	0.06720	0.05134	0.05254	0.05683	0.05658	0.03419	0.05210	101%	103%
Standalone Storage	0.06720	0.05134	0.05254	0.05683	0.05658	0.03419	0.05005	98%	99%
EV- NONDCFC	0.06720	0.05134	0.05254	0.05683	0.05658	0.03419	0.04920	96%	97%
EV- DCFC	0.06720	0.05134	0.05254	0.05683	0.05658	0.03419	0.04971	97%	98%

Table I-12 contains the Generation Energy marginal cost rates for the various technology types. The Generation Energy unit costs as presented in the summary shows that the unit cost of energy in each TOU period is identical across all customer subcategories; the analysis produced consistent marginal cost across technology types. However, rates vary incrementally on an annualized basis. The difference in the annual generation energy cost appears related to the time-of-use shape of energy consumption (kWh) for the different subcategory of customers included in the Study.

Table I-13
TOU-8-Secondary Distribution Peak Marginal Cost by DER Type

TOU-8-SEC Marginal Cost Rates Distribution Peak	Summer (\$/KW - Month)			Winter (\$/KW - Month)			Annualized \$/kW-Yr	% of Aggregate DER With Option E	% of NON DER
	On	Mid	Off	Mid	Off	Super-Off			
TOU-8-SEC Rate/Consumer Group Total	\$5.7	\$1.2	\$6.3	\$0.6	\$0.3	\$0.9	\$67.2		
NON DER	\$6.2	\$1.4	\$6.9	\$0.6	\$0.3	\$1.1	\$74.4		←
Aggregate DER with Option E	\$4.5	\$1.0	\$4.7	\$0.5	\$0.3	\$0.7	\$52.7	←	
Aggregate DER without Option E	\$4.5	\$1.0	\$4.7	\$0.5	\$0.3	\$0.7	\$52.5		
Option E (NONTECH)	\$4.7	\$1.3	\$4.9	\$0.5	\$0.3	\$0.8	\$56.5	107%	76%
NEM Only	\$5.5	\$1.2	\$5.1	\$0.6	\$0.3	\$0.8	\$60.9	116%	82%
Paired Storage	\$4.7	\$1.1	\$4.5	\$0.6	\$0.3	\$0.7	\$54.3	103%	73%
Standalone Storage	\$4.5	\$0.9	\$6.8	\$0.5	\$0.3	\$1.1	\$64.3	122%	86%
EV- NONDCFC	\$2.9	\$0.8	\$3.5	\$0.4	\$0.2	\$0.6	\$37.3	71%	50%
EV- DCFC	\$3.3	\$0.9	\$3.7	\$0.4	\$0.2	\$0.6	\$40.2	76%	54%

Table I-13 contains the Distribution Peak marginal cost rates for the various technology types. As seen above, Distribution Peak marginal cost rates are consistently lower across all technology types when compared to the NON DER category. On an annualized basis, EV-NONDCFC's and EV-DCFC's Distribution Peak marginal cost rates are much lower at approximately **50 percent** and **54 percent** of the

NON DER category respectively. NEM customers also show lower costs compared to the NON DER category at approximately **82 percent**.

Table I-14
TOU-8-Secondary Distribution Grid Marginal Cost by DER Type

TOU-8-SEC Marginal Cost Rates Distribution Grid	66 kV System \$/kW-Month	Distribution System \$/kW-Month	Total Grid Marginal Cost \$/kW-Month	Total Grid Marginal Cost \$/kW-Yr	% of Aggregate DER With Option E	% of NON DER
TOU-8-SEC Rate/Consumer Group Total	\$1.3	\$7.2	\$8.5	\$101.4		
NON DER	\$1.5	\$8.2	\$9.7	\$116.0	←	←
Aggregate DER with Option E	\$1.8	\$10.2	\$12.1	\$145.0	←	
Aggregate DER without Option E	\$1.8	\$10.2	\$12.0	\$144.4		
Option E (NONTech)	\$2.0	\$11.2	\$13.2	\$158.4	109%	137%
NEM Only	\$1.7	\$9.5	\$11.2	\$135.0	93%	116%
Paired Storage	\$1.7	\$9.5	\$11.3	\$135.1	93%	116%
Standalone Storage	\$1.4	\$7.9	\$9.3	\$111.3	77%	96%
EV- NONDCFC	\$2.3	\$12.7	\$15.0	\$179.7	124%	155%
EV- DCFC	\$2.1	\$11.5	\$13.6	\$163.1	112%	141%

Table I-14 contains the Distribution Grid marginal cost rate for the various technology types. As seen above all technology types have a greater Distribution Grid marginal cost when compared to the NON DER category except for Standalone Storage. On an annualized basis EV-NONDCFC and EV-DCFC have the largest variance when compared to the NON DER category with marginal cost rates approximately **155 percent** and **141 percent** of NON DER category respectively. The summary prompts inference that the EV subcategory of customers in general can have a noticeable impact on distribution grid costs. NEM customers show a higher grid cost than NON DER at approximately **116 percent**.

Table I-15
TOU-8-Secondary Annualized Marginal Cost by DER Type

TOU-8-SEC Marginal Cost Rates	Generation Capacity \$/KW - Yr	Generation Energy \$/KWh	Distribution Peak \$/KW - Yr	Distribution Grid \$/KW - Yr
TOU-8-SEC Rate/Consumer Group Total	\$58.3	\$0.05067	\$67.2	\$101.4
NON DER	\$55.9	\$0.05055	\$74.4	\$116.0
Aggregate DER with Option E	\$65.0	\$0.05133	\$52.7	\$145.0
Aggregate DER without Option E	\$67.3	\$0.05135	\$52.5	\$144.4
Option E (NONTech)	\$35.7	\$0.05118	\$56.5	\$158.4
NEM Only	\$72.1	\$0.05212	\$60.9	\$135.0
Paired Storage	\$49.5	\$0.05210	\$54.3	\$135.1
Standalone Storage	\$39.9	\$0.05005	\$64.3	\$111.3
EV- NONDCFC	\$28.4	\$0.04920	\$37.3	\$179.7
EV- DCFC	\$89.6	\$0.04971	\$40.2	\$163.1

Table I-15 contains a summary of the Generation Capacity, Generation Energy, Distribution Peak and Distribution Grid annualized marginal cost rates for the various technology types. As seen above, variation exists within technology types with respect to the direction of costs. For example, we see EV-NONDCFC has lower marginal cost rates for Generation Capacity, Generation Energy, and Distribution Peak when compared to the other technology types. However, the Distribution Grid marginal cost rate is higher than the other technology types including NON DER.

Table I-16
TOU-GS-2 Annualized Marginal Cost by DER Type

TOU-GS-2 Marginal Cost Rates	Generation Capacity \$/KW - Yr	Generation Energy \$/KWh	Distribution Peak \$/KW - Yr	Distribution Grid \$/KW - Yr
TOU-GS-2 Rate/Consumer Group Total	\$45.5	\$0.05037	\$58.1	\$87.6
NON DER	\$53.9	\$0.05048	\$64.5	\$95.9
Aggregate DER with Option E	\$32.3	\$0.05048	\$45.6	\$103.7
Aggregate DER without Option E	\$41.3	\$0.05260	\$41.0	\$109.5
Option E (NONTech)	\$29.0	\$0.04980	\$48.1	\$101.6
NEM Only	\$45.4	\$0.05291	\$39.3	\$111.2
Paired Storage	\$38.1	\$0.05303	\$49.8	\$112.2
Standalone Storage	\$39.5	\$0.05057	\$59.3	\$102.0
EV- NONDCFC	\$14.4	\$0.05213	\$24.2	\$96.4
EV- DCFC	\$18.9	\$0.04877	\$12.1	\$107.0

Table I-16 contains a summary of the Generation Capacity, Generation Energy, Distribution Peak and Distribution Grid annualized marginal cost rates for the various customer subcategories included in the TOU-GS-2 rate/consumer group. SCE includes this additional summary here to provide a direct comparison of results for the TOU-GS-2 class using the MCRR method of deriving cost-to-serve with the summary of results presented in the Rates Analysis section for this same rate/consumer group.

Conclusion and Inference

Through both an exhaustive Rates Analysis and MCRR model development by DER type, the original goals of the DER Class Study have found somewhat consistent results. Cost shift concerns, including the concerns around the contribution to margin for the Option-E subcategory of customers who have not adopted DER solutions, are refuted through the observation of sizeable contributions to margin when viewing such margins relative to unscaled Marginal Cost Rates. While both versions of the analysis found observable patterns in different cost drivers among customers who adopt DER solutions. For some subcategories of customers with limited adoption rates, SCE found that the limited confidence in the estimates provides limited inference on the potential cost-shift that can materialize between subgroups of customers adopting those DER solutions and the non-adopters in the rate/consumer group. As SCE analyzed

the various cost parameters included in the Study for each customer subcategory, observable differences in cost-to-serve were generally dependent on the blend of the customers coincident demand to SCE's current definitions of drivers of cost and/or the corresponding time-of-use determinants used in rates for the recovery of those costs – specifically, customer subgroups that adopt storage technologies like EVs, Paired Storage and Standalone storage can induce flexibility in their load shapes that affect their contribution to costs. Until greater adoption of these technologies occurs, conclusions about developing a DER class, or the corresponding rates suitable for that class, appears counter to both Bonbright principles of utility rate design as well as the CPUC's DER Action Plan to support California's climate goals.¹⁹⁷ As adoption rates continue to mature within each rate/consumer group in subsequent GRC cycles, SCE sees merit in continuing to perform such analysis to provide much-needed insight into both the development of rates as well as determining the merits of class categorization for specific subgroups of customers who adopt DER solutions. Customers who adopt DER solutions that complement consumption behavior in a manner that harvests load flexibility for the grid, can leverage rate options, including Option E tariffs, which in some cases may offer cost savings beyond the larger rate group's retail rate. The Study shows that cost causation principles are an important foundation to eventually determining a DER class, but that a) there is not sufficient adoption to do so currently; and b) more mature adoption is necessary to have the data that provides sufficient confidence in results to warrant the design of a new rate/consumer group. Because year-on-year changes in adoption levels for all technology types can be a dynamic and non-linear process, a stable benchmark for re-evaluation should be the GRC cycle where SCE can revisit this analysis to proactively assess the merits of a new class or the important considerations that shape the design of new rates structures.

¹⁹⁷ CPUC DER Action Plan at p. 8.

Appendix J

Economic Development Rate Proposed Agreement Changes

**ECONOMIC DEVELOPMENT RATE-RETENTION AGREEMENT
(Post-Decision 18-11-027)**

This Agreement is entered into between _____,
("Customer") _____, (Service Account(s)),
located at _____

_____, and Southern California Edison Company ("SCE"), located at 2244 Walnut Grove Avenue, Rosemead, California 91770. This Agreement shall become effective as of the date set forth beneath SCE's signature on the signature page of this Agreement. This Economic Development Rate-Retention ("Agreement") provides Customer with a discount for electric energy purchased over the five-year term of the Agreement.

~~For Small Customer Accounts, a~~ Additional applicable Service Accounts and Addresses are:

(T)

Service Account	Service Address

This Agreement is a filed form tariff agreement authorized by the California Public Utilities Commission ("Commission") for use by SCE. No officer, inspector, solicitor, agent, or employee of SCE has any authority to waive, alter, or amend any part of this Agreement except as provided herein or as authorized by the Commission. This Agreement is to be used in conjunction with Schedule EDR-R of SCE's Commission-approved tariffs, and supplements the terms and conditions of Customer's electric service under Customer's Otherwise Applicable Tariff, which is Schedule _____, and all related agreements.

The Parties agree as follows:

1. DEFINITIONS

As used in this Agreement, the following terms shall have the following meanings:

- 1.1 Added Facilities: Equipment or facilities that are in addition to, or in substitution for, standard facilities that SCE would normally install in order to provide electric service to Customer.
- 1.2 Agreement: This document and appendices, as amended from time to time.
- 1.3 Base Period Usage: As defined in Section 3 of this Agreement.
- 1.4 Customer: Customer as defined in SCE's Rule 1.
- 1.5 Forecast Maximum Demand: Customer's forecast of its Total Load maximum demand during the five years of this Agreement.

- 1.6 Incremental Added Facilities: Added Facilities that are required by SCE or requested by Customer to be installed in order to accommodate Customer's load, including any expansion under Schedule EDR-R.
- 1.7 Interest Rate: The 90-day commercial paper rate.
- 1.8 Liquidated Damages: Damages owed by Customer to SCE as provided in Section 10 of this Agreement.
- 1.9 Minimum Load: The minimum load Customer has agreed to purchase annually as established for Customer in Section 4.
- 1.10 Otherwise Applicable Tariff (OAT): The rate schedule, including any riders, under which Customer is taking electric service from SCE at the time of signing this Agreement or after, and any applicable successor schedule.
- 1.11 Party, Parties: The parties to this Agreement are SCE and Customer, as defined above.
- 1.12 Economic Development Rate-Retention (EDR-R): The rates and charges set forth in Schedule EDR-R, subject to the terms and conditions of this Agreement.
- 1.13 North American Industry Classification System ("NAICS") Code: An industry coding system developed jointly by the U.S., Canada, and Mexico to provide new comparability in statistics about economic activity across North America.
- 1.14 Premises: This term shall mean at the ~~same~~ physically and operationally related facility(s). [\(C\)](#)
- 1.15 Small Customer Account: A Customer Account with load below 150 kW that is not subject to the 150 kW eligibility requirement.
- 1.16 Standard Industrial Classification ("SIC") Code: The published codes in the 1987 Standard Industrial Classification Manual issued by the Executive Office of the President, Office of Management and Budget, as may be updated in SCE's discretion.
- 1.17 Total Load: Customer's recorded (metered) load (energy and demand), as may be aggregated at the same Premises.
- 1.18 Uncontrollable Force(s): An Uncontrollable Force is an event or occurrence due to influences outside the reasonable control of either or both Parties that could not have been prevented by the exercise of due diligence.

2. ECONOMIC DEVELOPMENT RATE-RETENTION

- 2.1 Customer represents that their NAICS 4-digit Code is _____, or their SIC 3 or 4-digit Code is _____.
- 2.2 Customer further represents that it meets the applicability requirements of Schedule EDR-R.

- 2.3 Subject to the terms and conditions of this Agreement, SCE will provide 12 percent off the Customer's bill calculated based on the rate components comprising its OAT (excluding the generation service cost component unless that service is provided by SCE) for purchases of electricity (demand and energy) over the five-year term of this Agreement.
- 2.4 Customer must maintain Total Load demands of at least 150 kW during each of the five years of service under this Agreement, either individually or on an aggregate basis for all accounts at the same Premises. Notwithstanding this provision, Customer can have a lower Total Load demand if the Service Account subject to this Agreement qualifies as a Small Customer Account.
- 2.5 If Customer plans to move or consolidate operations already located in SCE's service territory in connection with Customer's decision to remain in California, Schedule EDR-R shall apply to the Customer's operations as moved or consolidated, so long as all of the operations subject to Schedule EDR-R and this Agreement meet the applicability requirements of Schedule EDR-R.
- 2.6 If Section 2.5 is applicable, Customer must describe the locations that will be moved or consolidated, indicating the kW of each, as included in Forecast Maximum Demand. Customer must also describe any plans for expansion over the term of this Agreement.

3. BASE PERIOD USAGE

- 3.1 Base Period Usage must be established for each Customer to determine its Minimum Load. For Customers aggregating multiple accounts at a single Premises to meet the Total Load demand provisions specified above, BPU is established for the aggregation as a whole and not on an individual Service Account basis.
- 3.2 Base Period Usage is an average of Customer's historical monthly energy usage (kWh) and demand (kW) (provided Customer is served on an OAT with demand charges) by season and time-of-use where applicable, and is computed by SCE from Customer's 12 most representative continuous months of usage out of the past 24 months. Base Period Usage for energy consumption (kWh) shall be computed on an average hourly basis, and for billing shall be expanded by the applicable number of hours in the billing period. Ordinarily, Customer's Base Period Usage is based on the energy and demand recorded by SCE on a calendar-month basis. In the absence of calendar month data, 12 billing periods of Customer's billing history will be used, which may not add up to 365 days.
- 3.3 If Customer is subject to billing on a time-of-use basis but does not have the requisite historical data to determine its actual Base Period Usage, SCE shall estimate Customer's load characteristics, including estimated demand and energy usage on a time-of-use basis, using available data. That calculation shall be used as Customer's Base Period Usage until recorded load data becomes available to more definitively establish Customer's load characteristics. When SCE can more accurately estimate Customer's actual load characteristics, Customer's Base Period Usage shall be established based upon the new recorded data.

3.4 Base Period Usage is established as follows:

<u>Facilities Related Demand</u>	<u>Average Monthly Base Period Usage (kW¹)</u>	<u>Average Hourly Base Period Usage, (kWh)</u>
		N/A
<u>Summer</u>		
On-Peak		
Mid-Peak		
Off-Peak		
OVERALL	_____	_____
<u>Winter</u>		
Mid-Peak		
Off-Peak		
Super- Off-Peak	_____	_____
OVERALL		

Base Period Usage Facilities Related Demand is computed as follows:

1. Determine a Facilities Related Demand for each month in the period used to establish Base Period Usage that is the greater of:
 - a. The maximum billing demand for the month, or
 - b. 50% of the highest of all the billing demands in the period used to establish Base Period Usage.
2. Compute the average of the monthly Facilities Related Demands thus determined. This is Base Period Usage Facilities Related Demand.

An “XXX” entered above indicates that the entry is not applicable to Customer’s Base Period Usage.

4. MINIMUM LOAD

- 4.1 Customer must maintain a Minimum Load for each year from the date service is first rendered under Schedule EDR-R for the five-year term of this Agreement.
- 4.2 The Minimum Load must be at least 150 kW, except for a Small Customer Account, or 75% of Base Period Usage. For Customers aggregating multiple accounts at a single Premises to meet the Total Load demand provisions specified above, the Minimum Load requirement applies to the aggregation as a whole and not on an individual Service account basis.
- 4.3 Small Customer Accounts notwithstanding, if during any year of service the Customer’s Total Load maximum demand falls below the Minimum Load in any three months, the Customer’s discounts under Section 2.3 above shall be suspended

¹ kW BPU may not be applicable for Small Customer Accounts.

for the balance of the year and such suspension shall begin with the month of the third occurrence. Customer's discounts applicable to Total Load shall resume at the **beginning date specified in Section 5.3** of the following year, subject to the terms of this provision. For purposes of this section, a year of service commences with the start of the discount set forth above in Section 2.3.

(C)

- 4.4 Any load reductions shown to be directly attributable to energy efficiency measures implemented after establishing Base Period Usage in this Agreement shall not adversely impact the calculation of Customer's Minimum Load. The imputed load reductions attributable to any energy efficiency measure implemented subsequent to the establishment of Base Period Usage shall be added back into the load calculation in the event that Customer's usage falls below the Minimum Load. Provided that Customer maintains usage of at least the Minimum Load, net of any energy efficiency impacts, all Customer discounts shall apply.

5. COMMENCEMENT OF SERVICE

- 5.1 SCE will begin providing service under Schedule EDR-R at the start of the next regular billing period following the date the Customer notifies SCE that service should begin under Schedule EDR-R, which date shall not be more than 12 months from the effective date of this Agreement.
- 5.2 If Customer notifies SCE that it plans to move or consolidate operations with qualifying load that will be billed under Schedule EDR-R, then SCE will begin providing service under Schedule EDR-R with the next regular billing period following the date Customer notifies SCE that service should begin under Schedule EDR-R, which date shall not be more than 12 months from the effective date of this Agreement.
- 5.3 Customer estimates that service under Schedule EDR-R shall commence at the start of the next regular billing period beginning after _____ and shall provide SCE at least five business days' notice of any change in such date.

6. ADDED FACILITIES

An Added Facilities Contract, SCE's Form 16-308 or 16-309, shall be required if additional equipment or facilities are required for Added Facilities or Incremental Added Facilities.

7. ACKNOWLEDGMENT

- 7.1 Except as otherwise amended herein, Customer acknowledges that it is fully subject to all terms and conditions contained in Customer's OAT, or its successor rate schedule, all of SCE's rules, and all terms and conditions of service contained in SCE's Commission-approved tariffs. Any provision pertaining to either a peak period rate limiter or an average rate limiter does not apply.
- 7.2 Customer also acknowledges that SCE may request documentation to support Customer's signed Affidavit and may verify any supporting documentation and statements Customer has made in support of its signed Affidavit.

- 7.3 Customer also acknowledges that SCE is under a compliance mandate from the California Public Utilities Commission to provide to the Commission, under seal, (a) a list of the names and locations of its EDR participants, (b) their SIC Codes, (c) the total EDR discount provided to the Customer, (d) a listing of jobs retained or created during the relevant period that are attributable to the named EDR participant's involvement in the EDR program; and (e) the amount of the wage and benefits attributable during the relevant period to each category of job retained or created by the named EDR participant's involvement in the EDR program. Customer acknowledges that it is to provide to SCE **by no later than January 31 of each reportable year** any of the information above upon request in order to remain eligible to take service pursuant to this Agreement. Failure to timely furnish this information could lead, in SCE's sole discretion, to revocation of this Agreement. SCE shall use reasonable means to protect this data from public disclosure by redacting or aggregating it in any public filings.

8. TERM

- 8.1 This Agreement shall be effective for five years following the commencement of service under Schedule EDR-R pursuant to Section 5 of this Agreement.
- 8.2 At the end of the fifth year, Customer will no longer take service under Schedule EDR-R and will be billed only under its OAT effective with the start of the next regular billing period following the end of the fifth year of service under this Agreement.
- 8.3 This Agreement is not renewable at the expiration of its term, nor can the beneficiary of this Agreement take service on an EDR rate again for the same load served under this Agreement.

9. TERMINATION

This Agreement may be terminated (subject to payment of Liquidated Damages as provided in Section 10) by either party upon written notice as follows.

- 9.1 Termination for Misrepresentation or Fraud: SCE may terminate this Agreement upon five business days' notice if any representation made by Customer in this Agreement is untrue in any material respect, or if any statement in Customer's Affidavit was untrue, or if SCE determines that Customer was not eligible for Schedule EDR-R when this Agreement was signed, in which case Liquidated Damages as set forth in Section 10.3 shall be paid.
- 9.2 Termination at Customer's Request: Customer may request termination of this Agreement at any time by providing at least 60 days' written notice to SCE.
- 9.3 Termination For Nonpayment: SCE may terminate this Agreement if Customer fails to pay any amount due, under Schedule EDR-R within 30 days after receipt of notice of nonpayment from SCE. Customer shall be liable for all unpaid amounts and any accrued interest on the unpaid amounts.
- 9.4 Termination For Noncompliance: SCE may terminate this Agreement upon five business days' notice if Customer fails to comply with any term or condition of Schedule EDR-R or this Agreement, ~~or if Customer ceases the operations to which this Agreement applies or moves such operations out of SCE's service territory.~~

- 9.5 Termination For Ineligibility: SCE may terminate this Agreement upon five business days' notice if it determines that Customer has become ineligible for Schedule EDR-R.
- 9.6 Termination For Failure To Maintain Minimum Load: SCE may terminate this Agreement if Customer fails to maintain its Minimum Load during any consecutive 12 month period or shuts down its operations. If Customer fails to maintain its Minimum Load, SCE must provide Customer at least 90 days' notice of termination and Customer shall have the opportunity to increase its load to the Minimum Load and demonstrate to SCE's satisfaction that it will continue to use its Minimum Load for the remaining term of this Agreement.
- 9.7 Termination For Failure To Commence Service: SCE may terminate this Agreement if Customer does not begin service within 12 months after the date this Agreement was executed.
- 9.8 Termination for Ceasing Operations: SCE may terminate this Agreement upon five business days' notice if Customer ceases the operations to which this Agreement applies or moves such operations out of SCE's service territory.

10. LIQUIDATED DAMAGES

- 10.1 Upon termination of this Agreement, prior to its five-year term pursuant to Sections 9.1, 9.2, 9.3, 9.4, 9.5, or 9.6, Customer shall be required to pay SCE Liquidated Damages. The Liquidated Damages are required to ensure that neither SCE nor its ratepayers are financially or otherwise damaged if this Agreement is prematurely terminated before the end of its term.
- 10.2 It would be extremely difficult for the Parties to identify the amounts of increased or additional costs attributable to termination of this Agreement. Parties agree the Liquidated Damages specified herein are a reasonable approximation of damages which SCE and its ratepayers may incur as a result of such termination, and that the damage amount does not represent a penalty.
- 10.3 For termination under Section 9.1 above, Liquidated Damages under this Agreement shall be an amount equal to 200 percent of the cumulative difference between (i) the amount the Customer would have paid for its energy and demand if billed at their OAT, from the date service was first rendered under Schedule EDR- R, to the date of termination, and (ii) the amount billed to Customer under this Agreement and Schedule EDR-R during the same period.
- 10.4 For termination under Sections 9.2, 9.3, 9.4, 9.5, or 9.6 above (excepting business closure or reduction in load without relocation) Liquidated Damages under this Agreement shall be an amount equal to 100 percent of the cumulative difference between (i) the amount billed to Customer under Schedule EDR-R from the date service was first rendered under Schedule EDR-R to the date of termination, and (ii) a "proxy" bill calculation based on a declining discount starting at 20 percent of the Customer's OAT bill in year one with that annual discount reduced by 4 percent each year thereafter during the same period, *i.e.*, a discount of 16 percent in year 2, 12 percent in year 3, 8 percent in year 4, and 4 percent in year 5, plus interest on that difference (at the Interest Rate) to the date of payment. Should a Customer's usage increase such that cumulative liquidated damages become negative upon contract termination, under no circumstances will SCE be liable for paying liquidated damages to a Customer.

(D)

- 10.5 After termination of this Agreement for any cause, Customer shall be billed at its OAT.
- 10.6 The limitations of Rule 17 of SCE's Commission-approved Tariffs shall not apply to amounts payable under this Agreement.

- 10.7 SCE may in its discretion require Customer to establish a letter of credit or other security as a condition to providing service under Schedule EDR-R to secure payment of any Liquidated Damages.

11. UNCONTROLLABLE FORCE

- 11.1 Neither Party shall be considered to be in default in the performance of any obligation under this Agreement, except for obligations to pay money, when and to the extent that failure of performance shall be caused by an Uncontrollable Force.
- 11.2 If either Party, because of an Uncontrollable Force, is rendered wholly or partly unable to perform its obligations under this Agreement, the Party shall be excused from whatever performance is affected by the Uncontrollable Force to the extent the following conditions are met.
- 11.2.1 The suspension of performance is of no greater scope and of no longer duration than is required by the Uncontrollable Force.
- 11.2.2 The nonperforming Party uses its best efforts to cure its inability to perform. This subsection shall not require the settlement of any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to its interest. It is understood and agreed that the settlement of strikes, walkouts, lockouts or other labor disputes shall be at the sole discretion of the Party having the difficulty.
- 11.2.3 When the nonperforming Party is able to resume performance of its obligations under this Agreement that Party shall give the other Party written notice to that effect immediately.
- 11.3 Nonperformance due to Uncontrollable Force shall be excused, provided Party can demonstrate that the Uncontrollable Force was owing to causes outside its reasonable control and the occurrence of the Uncontrollable Force could not have been prevented by the exercise of due diligence.
- 11.3.1 Accordingly, nonperformance shall be excused from the date of the occurrence of the Uncontrollable Force, provided the nonperforming Party has given the other Party written notice describing the particulars of the occurrence within two weeks of the event.
- 11.3.2 Accordingly, nonperformance shall be excused from the date on which the nonperforming Party gives the other Party written notice describing the particulars of the occurrence of the Uncontrollable Force, if such written notice is given more than two weeks after the Uncontrollable Force occurred.
- 11.4 If Customer experiences an Uncontrollable Force that prevents Customer from complying with Schedule EDR-R and this Agreement, Customer may request that SCE suspend the terms of Schedule EDR-R and this Agreement for the duration of the Uncontrollable Force. Customer will be billed at their OAT for the duration of the suspension of this Agreement. Resumption of the terms of Schedule EDR-R and this Agreement shall commence with the next regularly scheduled billing period. In addition, the term of this Agreement will be extended for up to 12 months beyond the term originally established in this Agreement by the length of time this Agreement was suspended.

11.5 The occurrence of an Uncontrollable Force shall not (i) prevent SCE from terminating this Agreement in accordance with Sections 9.4 and 9.5 or (ii) extend the period any level of discount is available as provided in Section 2.3.

11.6 If the Uncontrollable Force causing the nonperformance is caused by the actions or inactions of legislative, judicial or regulatory agencies, or other proper authority, this Agreement may be amended to comply with the legal or regulatory change causing the nonperformance. Any such amendment must be first authorized by the Commission prior to implementation.

12. DAMAGE LIMITATION

SCE shall not be liable for any consequential, incidental, indirect, or special damages, whether in contract, tort, or strict liability including, but not limited to, lost profits and loss of power resulting from power outages or other electric service interruptions or from SCE's performance or nonperformance of its obligations under this Agreement or in the event of termination of this Agreement.

13. INDEMNITY

Customer shall, at its own cost and expense, defend, indemnify, and hold harmless SCE, its officers, agents, employees, assigns, and successors in interest, from and against any and all liability, damages, losses, claims, demands, actions, cause of action, costs, including attorney's fees and expenses, or any of them, resulting from the death or injury to any person or damage to any property caused by Customer, its employees, officers and agents, or any of them, and arising out of the performance or non-performance of its obligations under this Agreement. Termination of this Agreement shall not exempt Customer from the terms and conditions of this Section.

14. ASSIGNMENT OF AGREEMENT

Customer shall not assign this Agreement or any part or interest thereof, to a third party without the prior, written consent of an authorized representative of SCE. Any assignment made without such consent shall be void and of no effect. Further, any assignment made under this Agreement shall be subject to any applicable Commission authorization or regulation except as waived by the Commission.

15. AMENDMENT

Any changes or amendments to this Agreement must be in writing and must be executed by the Customer and SCE and, if required, be approved by the Commission.

16. NOTICE

Any notice either Customer or SCE may wish to provide the other regarding this Agreement must be in writing and may be transmitted by hand, fax, email or postal mail. Notices delivered by hand shall be deemed effective when delivered. Notices delivered by fax, email and mail shall be deemed effective when received.

Customer:

(name)

(title)

(party)

(address)

(city, state, & zip code)

SCE: Manager, Economic Development Services
Southern California Edison Company
6070-F No. Irwindale Avenue
Irwindale, CA 91702

17. NON-WAIVER

The failure of either Party to enforce any of the terms and conditions or to exercise any right or privilege in this Agreement shall not be construed as a waiver of any such terms and conditions or rights or privileges, and the same shall continue and remain in force and effect as if no such failure to enforce or exercise had occurred.

18. SEVERABILITY

In the event that any of the provisions, or portions thereof, of this Agreement are held to be unenforceable or invalid by the Commission, or any court of competent jurisdiction, the validity and enforceability of the remaining provisions or any portion thereof shall not be affected. However, should either party determine, in good faith, that such unenforceability renders the remaining provisions of this Agreement economically infeasible or disadvantageous, said party may terminate this Agreement upon 15 days' notice, except that the provisions of Section 10, Liquidated Damages, shall apply to any such termination.

19. APPLICABLE LAWS, RULES, AND REGULATIONS

This Agreement shall be subject to, and interpreted under, the laws, rules, and regulations of the State of California and the Commission, and under SCE's Commission-approved Tariff Schedules and Rules. To the extent there are any inconsistencies between this Agreement and SCE's other tariffs, this Agreement shall control.

20. CALIFORNIA PUBLIC UTILITIES COMMISSION

- 20.1 This Agreement shall at all times be subject to such changes or modifications by the Commission as said Commission may, from time to time, direct in the exercise of its jurisdiction.
- 20.2 Notwithstanding any other provisions of this Agreement, SCE has the right to unilaterally file with the Commission, pursuant to the Commission's rules and regulations, an application for a change in rates, charges, classification, service, or rule, or any agreement relating thereto.

20.3 This Agreement shall be subject to review in any proceeding the Commission may conduct regarding SCE's EDR program implementation.

21. ENTIRE AGREEMENT

This Agreement, including SCE's tariffs as filed with the Public Utilities Commission, constitutes the sole, only, and entire agreement and understanding between the Parties as to the subject matter of this Agreement with respect to Schedule EDR-R. Prior agreements, commitments or representations, whether expressed or implied, and discussions between Parties, shall not be construed to be a part of this Agreement.

22. AUTHORIZATION SIGNATURES

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized agents to be effective on the date of SCE's signature below.

By: SOUTHERN CALIFORNIA
EDISON COMPANY

By: CUSTOMER

(Signature)

(Signature)

(Name)

(Name)

(Title)

(Title)

Southern California Edison Company

(Customer)

(Date)

(Date)

AFFIDAVIT FOR ECONOMIC DEVELOPMENT RETENTION RATES

By signing this affidavit, an Applicant who retains load in the service territory of Southern California Edison (SCE) hereby certifies and declares under penalty of perjury under the laws of the State of California that the statements in the following paragraphs are true and correct:

1. But for the receipt of the applicable discounted EDR and the terms of the corresponding EDR-R Agreement, either on its own or in combination with an economic development incentive package, the Applicant's load would not be retained within California.
2. Applicant has discussed with SCE the cost-effective conservation and load management measures the Applicant may take to reduce their electric bills and the load they place on SCE's system.
3. Customer confirms that its NAICS Code(s) and SIC Code(s) are as stated in the applicable EDR-R Agreement and that it is eligible for the applicable EDR-R schedule.
4. Customer certifies that all load subject to the applicable EDR-R Agreement represents load that is eligible for the applicable EDR-R schedule and is existing load that is being retained within California.

Executed this _____ day of _____, _____.

By: APPLICANT _____

Signature:

Name:

Title: